Economic Benchmarking RIN
Basis of Preparation

1 July 2019 to 30 June 2020

Part of Energy Queensland

Contents

BOP – Cost Allocation Method Recast

Annual Reporting, Economic Benchmarking, and Category Analysis Regulatory Information Notice - Financial Templates

Requirement to recast financial information

This Basis of Preparation Document describes the process to report overheads in accordance with the AER's approved CAM's (Ergon Energy Cost Allocation Method Version 5, and Energex's Cost Allocation Method Version 3a) applicable to the 2019-20 regulatory year. It is an overarching approach inserted at the beginning of this document as it impacts all overhead costs for Ergon Energy and Energex reported in financial templates for the Annual Reporting (including Workbook 2), Economic Benchmarking, and Category Analysis Regulatory Information Notices.

The Cost Allocation Method Recast work was undertaken by Energy Queensland (EQL) for Distribution Network Services Providers (DNSP), Ergon Energy and Energex. Any reference to Energex does not impact the Ergon Energy CAM recast, or vice versa.

EQL is implementing, a single Enterprise Resource Planning (ERP) and Enterprise Asset Management (EAM) system in SAP, which will impact reporting in Regulatory Information Notices (RIN) to the Australian Energy Regulator (AER) in 2019-20. EQL is the parent entity of Distribution Network Services Providers Ergon Energy and Energex.

On 22 November 2018, the AER approved a combined Ergon Energy and Energex Cost Allocation Methodology (2020-25 CAM) to take effect from 1 July 2020, at the commencement of the new regulatory control period. Additionally, the existing CAM's (Interim CAMs[1]) were approved by the AER to reflect our new corporate structure to take effect from 1 December 2018.

On 1 July 2019, the existing ERP, Ellipse, adopted the 2020-25 CAM 1 year earlier than the AER's approved effective date for statutory reporting and general ledger (GL) purposes. As such, statutory and regulatory reporting requirements diverged in 2019-20, and hence created a need to recast Ellipse general ledger transactions for regulatory reporting purposes.

The Reporting and Analytics Transition and Sustainability (RATS) Project rebuilt reporting capability for regulatory reporting in 2019-20 by developing a CAM Recast Model using an SAP Enterprise Intelligence Platform (EIP).

Compliance with Requirements

Regulatory Information Notices require information to be provided in each regulatory template in the Microsoft Excel Workbooks completed in accordance with the approved cost allocation method which

[1] Ergon Energy AER approved CAM (Version 5), Energex's AER approved CAM (version 3a) effective 1 Dec 2018.

applies to the relevant regulatory year.

The Table below demonstrates how the information provided by Ergon Energy and Energex is consistent with each of the requirements specified by the AER.

Table 1-1 Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex Ltd and Ergon Energy Ltd Cost Allocation Method AER Final Decision November 2018 - Section 1.1 Summary: In November 2018 the AER approved all three proposed amended CAM's under clause 6.15.4(c) of the rules. The current CAM for Ergon Energy and Energex became effective from 1 December 2018.	Ergon Energy and Energex applied the AER approved CAM's (Ergon Energy Cost Allocation Method Version 5, and Energex's Cost Allocation Method Version 3a) which became effective from 1 December 2018.
Ergon Energy and Energex Interim CAM's Section 10 and 13 CAM Consistency: Policies and principles relating to allocations will be consistently applied across accounting periods to ensure that regulatory financial reports are prepared on a consistent basis over time.	Ergon Energy and Energex have applied the CAM consistently across accounting periods for consistency.
Ergon Energy and Energex Interim CAM's Section 11 and 14 Interim Record Keeping: • The ERP provides the capability to record and report all financial information based on the CAM principles and policies for both statutory and regulatory purposes. • All records will be appropriately retained in accordance with regulatory and legislative requirements. All information submitted to the AER through regulatory information notices is subject to external audit prior to submission.	Ergon Energy and Energex's ERP and Corporate Support Costs Allocation Models are the underlying data source and basis for which overhead rates were derived to be applied in the CAM Recast Model providing an auditable record.
Ergon Energy and Energex Interim CAM Section 12 and 15 Monitoring compliance with the CAM and CAG: The Finance and Corporate Services Business Unit is responsible for monitoring compliance with the CAM for Ergon Energy and Energex. Operationally, the General Manager Financial Control will be responsible on a day to day basis for compliance.	Ergon Energy and Energex's annual statutory financial statements and the ERP are reviewed by our external auditors. Ergon Energy and Energex has also undertaken independent audit of the regulatory reporting statements for compliance with regulatory reporting requirements, including the CAM.

Annual Reporting RIN Appendix F Definitions; Economic Benchmarking RIN Appendix 9 Definitions; Category Analysis RIN Definitions and Interpretation. 'Actual Information' definition: • Information presented in response to the Notice whose presentation is materially dependent on information recorded in Ergon Energy and Energex's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice. 'Accounting records' include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate Ergon Energy and Energex's regulatory accounts and responses to the Notice. 'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on.	The regulatory reporting statements have been prepared in accordance with the Ergon Energy and Energex's Interim CAM's that apply to 2019-20. We have reviewed the cost allocations for the current financial year to ensure they have been consistently applied in accordance with the CAM. In undertaking this review, we have implemented a CAM Recast Model. We confirm that all financial transactions from the general ledgers have been accurately replicated into the CAM Recast Model. We also confirm that the 2020-25 CAM transactions have been removed and that the 2015-20 CAM transactions have been accurately generated in the CAM Recast Model.

Sources

Ergon Energy and Energex use the Ellipse General Ledger as the source of information in the CAM Recast Model. General ledger instances are acquired in the same manner from base transactional tables in the operational systems. This transactional data is replicated in its entirety to the SAP Enterprise Intelligence Platform (EIP) via legacy data warehouses.

This is a two-step replication with the first using SharePlex to monitor and apply changes at the Oracle application table (MRF900) into a matching Oracle data warehouse table. This SharePlex process has been successfully performed for 10 years and is monitored by real-time system checks and periodic database administrator health checks.

The second step replicates the data from these Oracle data warehouse tables into the EIP source containers using SAP Smart Data Integration (SDI) running every five minutes.

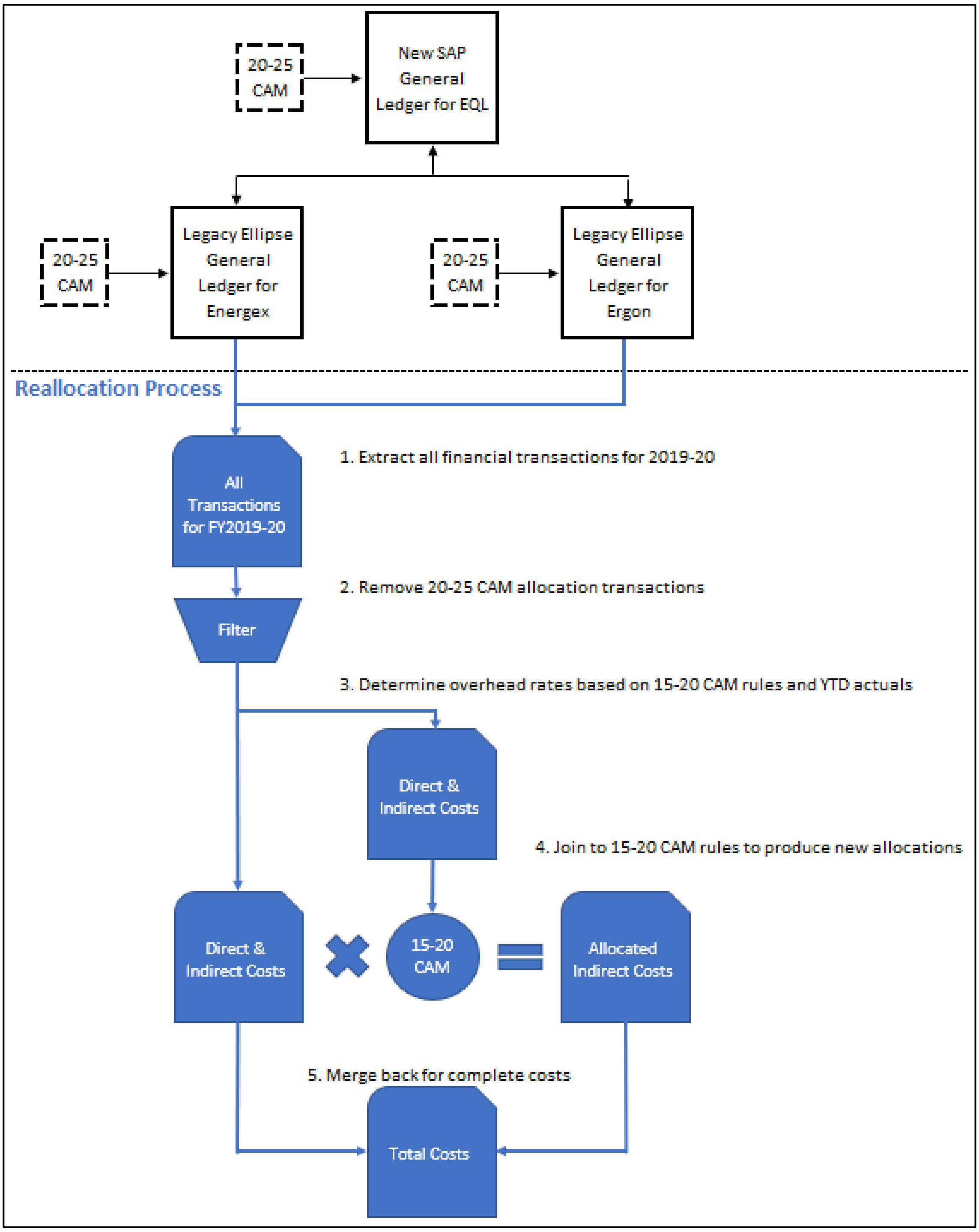
The resulting SAP EIP data is reconciled back to the Ellipse general ledgers through matching trial balances for current and prior periods.

The rules to be applied in the CAM Recast model are loaded via two spreadsheets respectively for Energex and Ergon Energy rates pertinent to those charts of accounts.

Methodology

The approach undertaken in the CAM Recast Model is outlined in Figure 1 below, to produce transactional data for 2019-20 regulatory reporting, by extracting overhead/CAM allocation entries from GL transactions and by reapplying overheads based on Interim CAM rules.

Figure 1-1 CAM Recast progress diagram



CALCULATION OF 2019-20 CAM RATES

Ergon Energy and Energex's previous year (2018-19) Corporate Support Costs Allocation Models were obtained from the Financial Planning team and updated with 2019-20 actual data to calculate 2019-20 overhead rates.

For Ergon Energy, the Responsibility Centre (RC) corporate allocation percentages to Unregulated lines of business were carried forward from the prior year. Analysis prepared by the Financial Planning team demonstrated this assumption would immateriality impact on results given allocations do not vary significantly year-on-year (less than ±2%).

All other inputs were updated with 2019-20 actual information obtained from the CAM Recast Model after the CAM allocation / overhead entries had been extracted. Financial year actual expenditure is used (as opposed to full year budget information), to derive the calculated rates. The use of actual costs to derive overhead rates resulted in an immaterial over or under recovery of overheads.

For specific categories of the model key points are noted below, including difference between Ergon Energy and Energex's approaches where they diverge.

Labour on-cost (Ergon Energy and Energex)

CAM business rules for 2018-19 and 2019-20:

- Same approach for Interim and 2020-25 CAMs (same pool / allocated based on same definition of W&S / included in direct costs);
- 2019-20 CAM workpapers also show that the rates are unchanged from 2018-19.

Materials on-cost (Ergon Energy and Energex)

CAM business rules for 2018-19 and 2019-20:

- Same approach for Interim and 2020-25 CAMs (same pool / allocated based on stores issues);
- Recalculated rates using 2019-20 year to date actuals and updated in the CAM Recast Model.

Fleet costing (Ergon Energy)

- 2018-19 (Interim CAM) approach involved fleet costing (into direct costs) with rates determined for each fleet class to recovery appropriate costs (including depreciation);
- New regulatory CAM (2020-25) moves to a simple allocation methodology, based on labour dollars incurred; and
- Statutory CAM / (Ellipse) GL approach continues with fleet costing for 2019-20, in line with the 2018-19 approach. Therefore, as this complies with the Interim CAM no changes are required.

Fleet costing (Energex)

- 2018-19 (Interim CAM) approach involved an allocation based on labour dollars to recover fleet costs (excluding depreciation)
- New regulatory CAM (2020-25) continues with the same simple allocation methodology, based on labour dollars incurred.
- However statutory CAM / (Ellipse) GL approach recovers fleet costs and fleet depreciation, using the same allocation methodology, based on labour dollars incurred.
- The CAM Recast Model has been updated with a new rate to recover year to date fleet costs only (not depreciation).

Unregulated Allocation (Ergon Energy)

- 2018-19 (Interim CAM) approach involved significant analysis each year, with input from across the business, to determine percentage allocations for each RC to unregulated lines of business;
- New regulatory CAM (2020-25) will allocate costs to unregulated as part of the three-factor methods for corporate overheads and network overheads;
- For 2019-20, new unregulated allocations have been determined using 2019-20 year to date expenditure for each RC but maintaining 2018-19 percentage allocations (refer to Assumptions). Analysis provided by the Financial Planning team indicates that there is minimal variation year to year in the percentage allocations and the conclusion is that the percentage allocations continue to be a fair reflection of the split of effort and cost to each line of business.
- Where costs appeared on new RC's during 2019-20, the function of that RC was determined and allocations were based on an existing RC which performs a similar function.

Unregulated Allocation (Energex)

- 2018-19 (Interim CAM) approach used a three-factor method to allocate costs to unregulated lines of business;
- New regulatory CAM (2020-25) will allocate costs to unregulated as part of the three factor methods for corporate overheads and network overheads;
- For 2019-20, the three-factor method has been updated with 2019-20 year to date expenditure.

1. Regulated Overheads (Ergon Energy and Energex)

- 2018-19 (Interim CAMs) approach identified all RCs included in the regulated overhead pool, with exclusions for specific activities, products and elements. The unregulated proportion (refer above) was also deducted to determine the size of the pool. The base (regulated program of work direct costs) was determined by activity ranges and specific elements. The pool is then divided into the base to determine the regulated overhead rate. Ergon Energy separates regulated overheads between Opex, Capex and Customer Care and determines separate overheads rates for each. Energex has a combined regulated Opex and Capex rate;

- For 2019-20, the process was repeated, using year to date data from the CAM Recast Model, with CAM allocation / overhead entries removed. Costs incurred in EQLD district were allocated to specific RCs in Ergon Energy and Energex, based on a model used by the Business Planning and Analysis team for 2018-19. Also, ICT and lease costs were added in. Refer to notes below on these topics.

a) Energy Queensland support costs (Ergon Energy and Energex)

- In prior years, costs incurred in EQLD district were allocated to specific RCs in Ergon Energy and Energex based on a model used by the Business Planning and Analysis team;

- This process was repeated for the 2019-20, adding the support costs attributable to each entity into the CAM Recast Model for inclusion into the respective overhead pools and allocation to the businesses.

b) ICT costs (Ergon Energy and Energex)

- In prior years, ICT costs were incurred in SPARQ and charged to DNSPs as Asset Usage Fees, Service Level Agreement (SLA) fees and Telecommunications costs;

- Under the 2020-25 CAM and in the GL for 2019-20, ICT assets have moved out of SPARQ and into the DNSPs. Assets (also Capex and Depreciation) are directly attributed to DNSPs where possible, with the remainder allocated using the CAM non-network principles (i.e.. allocated based on labour incurred). Asset Usage Fees have not been recorded in the General Ledger for 2019-20;

- Costs for the 2019-20 financial year have been allocated between Ergon Energy and Energex on the same basis as 2018-19 and added into to the CAM Recast Model for inclusion into the respective overhead pools and allocation to the businesses;

- This will be a one-off adjustment for the 2019-20 regulatory year, as the Statutory and Regulatory approaches will align in the 2020-25 regulatory period.

c) Lease costs (Ergon Energy and Energex)

- The Australian Accounting Board introduced AASB16 Leases in 2019-20 replacing AASB117;

- Leases are now on-balance sheet for Statutory Reporting purposes and in the General Ledger.

- To maintain consistency with the 2015-20 Distribution Determination and the AER approved CAM, lease costs were recalculated to show lease expense instead of on-balance sheet treatment with depreciation and interest.

- Lease expense for 2019-20 has been allocated between Ergon Energy and Energex and manually added into the overhead pools.

- This will be an ongoing adjustment for the 2019-20 regulatory year and the 2020-25 regulatory period for legacy leases, as the Statutory and Regulatory approaches differ.

CAM SPREADSHEET OVERHEAD RATES

The resulting CAM overhead rates calculated as detailed above, are then entered into a CAM rates file for each entity which provides the relevant Ellipse account strings attracting the on-cost or overhead along with the appropriate rate, account code to post the on-cost or overhead and the account code to post the recovery of that on-cost or overhead.

This is then used to feed into SAP EIP CAM Recast and apply the on-costs and overheads based on the 2019-20 CAM rules.

The extract below is from the Ergon Energy CAM rates file, showing that a specified account mask (usually applicable to an activity code within the ellipse account string) attracts a certain percentage of overheads, posting to element 8140 or 8100, with the recovery posting to element 8350.

C	D	E	F	G	H	I	J	K	L
[ACCT_MASK]	[RATE]	[JOURNAL_TYPE]	[MIN_LIMIT]	[OH_DSTRCT]	[OH_COST_CODE]	[OH_EXPS_ELEM]	[RV_DSTRCT]	[RV_COST_CODE]	[RV_EXPS_ELEM]
@@@@C2090@@@@@@@	002932	OH	000100	EECL	@@@@C2090@@@@	8140	EECL	5020510400000	8365
@@@@52000@@@@@@@	004739	OH	000100	EECL	@@@@52000@@@@	8100	EECL	0002625000000	8350
@@@@53@@@@@@@@@@	004739	OH	000100	EECL	@@@@53@@@@@@@	8100	EECL	0002625000000	8350
@@@@54@@@@@@@@@@	004739	OH	000100	EECL	@@@@54@@@@@@@	8100	EECL	0002625000000	8350
@@@@56@@@@@@@@@@	003909	OH	000100	EECL	@@@@56@@@@@@@	8100	EECL	0002625000000	8350
@@@@C200@@@@@@@@	004739	OH	000100	EECL	@@@@C200@@@@@	8100	EECL	0002625000000	8350
@@@@C201@@@@@@@@	004739	OH	000100	EECL	@@@@C201@@@@@	8100	EECL	0002625000000	8350

The extract below is from the Energex CAM rates file, showing that a specified account mask (usually applicable to an activity code and element combination within the ellipse account string) attracts a certain percentage of on-costs or overheads, posting to element 8102 (fleet on-cost), 8103 (materials on-cost) or 8104 (overheads), with the recovery posting to the same element but a recovery activity.

[CAM_RULE_REF]	[CAM_DST	[ACCT_MASK]	[RATE]	[JOURN	[OH_COST_CODE]	[OH_EXPS_ELEM]	[RV_DSTRCT]	[RV_COST_CODE]	[RV_EXPS_ELEM]
EGX101FLT40XXX3302	EGX1	@@@@40@@@@@@@3302@@@@	000859	OH	@@@@@@@@@@@@@	8102	EGX1	133098050P000	8102
EGX101FLT40XXX3312	EGX1	@@@@40@@@@@@@3312@@@@	000859	OH	@@@@@@@@@@@@@	8102	EGX1	133098050P000	8102
EGX101FLT41XXX3302	EGX1	@@@@41@@@@@@@3302@@@@	000859	OH	@@@@@@@@@@@@@	8102	EGX1	133098050P000	8102
EGX101FLTC2XXX3302	EGX1	@@@@C2@@@@@@@3302@@@@	000859	OH	@@@@@@@@@@@@@	8102	EGX1	133098050P000	8102
EGX101FLTC2XXX3312	EGX1	@@@@C2@@@@@@@3312@@@@	000859	OH	@@@@@@@@@@@@@	8102	EGX1	133098050P000	8102
EGX101FLTC35XX3302	EGX1	@@@@C35@@@@@@3302@@@@	000859	OH	@@@@@@@@@@@@@	8102	EGX1	133098050P000	8102
EGX101FLTC35XX3312	EGX1	@@@@C35@@@@@@3312@@@@	000859	OH	@@@@@@@@@@@@@	8102	EGX1	133098050P000	8102
EGX101MAT40XXX4400	EGX1	@@@@40@@@@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101MAT41XXX4400	EGX1	@@@@41@@@@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101MAT42XXX4400	EGX1	@@@@42@@@@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101MAT430XX4400	EGX1	@@@@430@@@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101MATC2XXX4400	EGX1	@@@@C2@@@@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101MATC30154400	EGX1	@@@@C3015@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101MATC35XX4400	EGX1	@@@@C35@@@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101MATC4XXX4400	EGX1	@@@@C4@@@@@@@4400@@@@	000532	OH	@@@@@@@@@@@@@	8103	EGX1	133098050P000	8103
EGX101OVH41XXX3302	EGX1	@@@@41@@@@@@@3302@@@@	006037	OH	@@@@@@@@@@@@@	8104	EGX1	133098050P000	8104
EGX101OVH41XXX3312	EGX1	@@@@41@@@@@@@3312@@@@	006037	OH	@@@@@@@@@@@@@	8104	EGX1	133098050P000	8104
EGX101OVH41XXX4400	EGX1	@@@@41@@@@@@@4400@@@@	005855	OH	@@@@@@@@@@@@@	8104	EGX1	133098050P000	8104
EGX101OVH41XXX4500	EGX1	@@@@41@@@@@@@4500@@@@	005529	OH	@@@@@@@@@@@@@	8104	EGX1	133098050P000	8104
EGX101OVH41XXX4900	EGX1	@@@@41@@@@@@@4900@@@@	005529	OH	@@@@@@@@@@@@@	8104	EGX1	133098050P000	8104

SAP EIP CAM RECAST MODEL

The CAM Recast model is a new SAP HANA database structure that is built on top of the landed data from Ellipse general ledgers and applying the rules and rates from specific Ergon Energy and Energex spreadsheets. However, the pattern is the same process as currently happens directly in the sourcing general ledgers where transactions are compared against defined account code masks and then where matched will generate two additional transactions (a primary and reversal overhead) at a percentage rate to the driving transaction.

Approach

The CAM Recast model passes all general ledger sourced transactions through the same process:

1. Current year (2019-20) transactions are identified:

- If a transaction is posted to a financial period outside the 2019-20 year then this is passed through, no further rules are applied, and these transactions appear in the results full and complete. The steps below are now only effective to those transactions falling into the 2019-20 financial year.

2. Ellipse 2019-20 overheads are stripped out:

- These are transactions specifically tagged by the automated legacy CAM processes with a journal type of "OH", or manual journals that specifically post to the segments dedicated to overhead costs. They are removed and do not contribute to further results.

3. New 2019-20 overheads are generated:

The spreadsheet rules for new CAM transactions are acquired and consist of:

- A filtering account code mask
- Overhead rate to be applied
- A primary account code, and
- A reversing account code.

Driving source transactions are identified by comparing against the defined filtering account code mask for a match (refer above section "CAM Spreadsheet Overhead Rates").

Driving source transactions related to user defined excluded expense elements or projects are disqualified (these exclusions consistently follow the CAM application rules whereby certain expense elements do not attract overheads due to their nature and a list of non-system building construction projects associated with a specific GL activity are exempt from overheads as they are wholly completed by external contractors).

All identified driving transactions then generate two new CAM transactions: i) a new primary overhead transaction and ii) a new reversing overhead transaction. The amounts are calculated from the driving transaction amount multiplied by the defined overhead rate in the matching rule (the reversing transaction is negated). Similarly, the segment applied comes from the primary and reversing account code in the matching rule.

The resulting CAM Recast model has all driving transactions from step 2 as well as all overhead transactions from step 3.

Note: the CAM spreadsheet rules are applied against the entire years transactions every time it is used, in real-time. There is no batch processing. This means if the rules or rates are changed then these are retrospectively applied to the entire year.

Version Control

The CAM Recast database model is an SAP HANA construct existing in the Energy Queensland (EQL) SAP Cloud Platform AWM instance. The model is maintained in a development environment and then migrated through testing environments before residing in a read-only production environment for business use. All source code is stored in a GIT repository with separately secured branches for work-in-progress and committed components.

The CAM rules and rates are mastered in separate Ergon Energy and Energex spreadsheets by the Finance team. These are maintained in secured folders and then authorised, released and loaded into the CAM Recast model from a separate HANA folder.

Reconciliations

The following reconciliations and controls were applied to provide assurance over the process:

- To verify the overheads applied by the CAM recast model a reconciliation of the output to the expected overhead based on a manual recalculation by direct activity was performed. In all cases, for both entities the on-costs and overheads applied by the model agreed within all material respects.

- The consolidated Energy Queensland pool of indirect costs was reconciled to the total cost pools calculated and utilised for deriving the CAM rates for Ergon Energy and Energex. This incorporated the known differences for treatment of Sparq costs and lease expenses and considered the underlying mappings of exclusions and unregulated costs as followed by the models used the calculate the indirect cost pools and overhead rates for each entity.

- A high-level reconciliation was performed for Ergon Energy and Energex comparing the original general ledger (as audited for Statutory purposes) to the Recast extract. The overall net profit/loss for those entities was compared pre and post recast identifying the financial impact of the different treatments of certain costs under the 2019-20 CAM and the 2020-25 CAM as reflected in the general ledger.

Assumptions

For 2019-20, with the implementation of the CAM Recast Model key points to note include:

- Direct expenditure remains unchanged as obtained from the same Ellipse GL codes, with transactions coded to account combinations of Responsibility Centre / Activity / Product / Expense Element;

- Overhead rates were recalculated using the 2018-19 overhead rate model which applies CAM business rules compliant with the Interim CAM using 2019-20 actual dollars as inputs;

- An assumption is applied Ergon Energy's Corporate Support Costs Allocation Model where corporate responsibility centre allocations were adopted from prior year inputs with sensitivity analysis supporting the assumption would result in immaterially different results.

Therefore, the conclusion is that the CAM Recast Model data extracts meet the definition of 'actual information' in accordance with annual RIN Notices (AR, EB, CA RIN's).

Estimated Information

Ergon Energy and Energex have provided Actual Information, in accordance with the AER's definition.

Explanatory Notes

Not applicable.

BOP - 3.1 Revenue

Table 3.1.1 - Revenue Grouping by Chargeable Quantity

Table 3.1.2 - Revenue Grouping by Customer Type or Class 1

Table 3.1.3 - Revenue (penalties) Allowed (deducted) Through Incentive Schemes

Compliance with the RIN Requirements

All mandatory data entry fields shaded yellow, have been populated.

Ergon Energy confirms, as required by the AER in Box 1, Revenue Financial Reporting Framework of Appendix B, Instructions and Definitions that Revenues reconcile to the Direct Control Services revenues in Regulatory Accounting Statements as per the Annual Reporting Requirements (AER defined term) as submitted to the relevant regulator, for the year in question).

Direct Control Services, which were charged by Ergon Energy to customers (in accordance with the EB RIN instructions at Section 2: Revenue) have been reported as

- Standard Control Services (SCS): Network Services, DUOS (including cross boundary duos); Capital Contributions; and
- Alternative Control Services (ACS): Public Lighting, Connection services, Metering services, and Ancillary services.

Public lighting for the recovery of construction and maintenance costs for the 2019-20 regulatory year has been reported as an ACS (refer to the source and methodology for Revenue Grouping by Chargeable Quantity under heading DREV0112: Public Lighting).

Ergon Energy's approved services are as per Attachment 13 (Classification of Services) of the

Australian Energy Regulator Final Distribution Determination (AER FDD). This correlates to Distribution use of System charges and Capital Contributions for SCS and Other Revenue and Contributions for ACS as displayed in the regulatory accounting statements.

Revenue reported in prior regulatory accounting statements which is not a Direct Control Service charged by Ergon Energy to Customers include: profit or gross proceeds on sale of assets, interest received, shared assets revenue and Transmission use of System charges. Rather, they were specific reporting requirements of prior regulatory instruments.

'Revenue from Unmetered Supplies' is the same for template 3, table 3.1.1 (DREV0107) as for template 3, table 3.1.2 (DREV0205). Public lighting has been reported in variable (DREV0112) and has been excluded from 'revenue from unmetered supplies' (DREV0107). This is based on the interpretation of the definitions for unmetered supplies and customer numbers. The latter states public lighting connections are not to be counted when calculating the number of unmetered customers.

DREV01: Total revenue by chargeable quantity for 2019-20 is the Total SCS Revenue reported in Ergon Energy's 2019-20 Annual Reporting RIN less Jurisdictional scheme amounts and TUOS revenue. The TUOS component of Cross Boundary Revenue is also excluded from the Total SCS Revenue (similar to 2017-18).

The total of revenues by chargeable quantity for these variables reconciles to the total revenues by customer class (DREV02).

'Revenue from Unmetered Supplies' is the same for template 3, table 3.1.1 ('DREV0107) as for template 3, table 3.1.2 (DREV0205)

As confirmed by the AER on 1 October 2014, the following variables are not applicable to Ergon Energy and accordingly have not been populated:

- DREV0303 F-Factor [Victorian specific factor];
- DREV0304 S-Factor True up [Victorian specific factor capturing the close out of the old ESCV s-factor scheme].

Consistent with prior submissions and advice received by the AER on 22 September 2017, Ergon Energy has also not populated the variable 'DREV0305 Other' for 2019-20.

Ergon Energy notes that the AER has changed the variable numbers associated with this table in its revised templates for 2013-14 (consistent with 2019-20). Therefore, care should be taken when reviewing variable data for 2019-20 against submissions prior to 2013-14.

Sources

Source Data for Tables 3.1.1 & 3.1.2

For year 2019-20, data has been sourced from Ergon's billing system PEACE. Monthly DMK billing reports, based on Statement of Charges monthly periods, are collated to provide actual data required. This data is then adjusted for Accrual data. DREV0203 and DREV0204: Data splitting High /Low voltage in table 3.1.2 is considered estimated.

Ergon Energy has sourced the Accrual data from the Ergon Energy's Annual Reporting RIN's for 2019-20.

For year 2019-20, Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to variables in Template 3, table 3.1.2, except for the high/Low voltage data which is still considered estimated-see above comment.

In addition to the calculations above DREV0201 - DREV0204 have been adjusted from a billed basis to an unbilled basis on a pro-rata basis.

The total at DREV02 must align with the total at DREV01. Therefore the total unbilled amount for DREV0201 - DREV0204 is equal to the total of DREV01 less DREV0205 and DREV0206 on an unbilled basis.

DREV0205 equals DREV0107, and DREV0206 equals the sum of DREV0111 and DREV0112.

The total unbilled amount for DREV0201 - DREV0204 is calculated and the difference between that and the billed amount for those variables is added as an adjustment amount to present those variables on an unbilled basis.

Source Data for Table 3.1.3

Incentive schemes applicable to Ergon Energy relate to the EBSS and STPIS schemes - commencing from 1 July 2010.

EBSS payments for performance during 2010-15 are a component of the building blocks set in the relevant AER distribution determination. The EBSS payment for 2019-20 has been sourced from the AER's SCS PTRM handed down as part of the final determination.

STPIS reward / penalty payments are added to revenues during the annual Pricing Proposal approval process. The reward / penalty under the STPIS scheme has been based on the STPIS revenue adjustment included in the TAR formula in the 2019-20 Pricing Proposal.

Methodology

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 3, table 3.1.1.

Table 1-1 Mapping of DCOS to RIN Variable below sets out the mapping of Distribution Cost of Supply (DCOS) model charges to RIN variables.

DCOS model or Billing reference	Benchmarking RIN Variable
NDFC Network DUos Fixed Charge$	Revenue from Fixed Customer Charges
NDFCG	

Network DUoS Fixed Charge Generation$	
NDCUC Network DUoS Connection Unit Charge$	
NDKVACC Network DUoS kVA Capacity Charge$	Revenue from Contracted Maximum Demand Charges
NDTDC Network DUoS Threshold Demand Charge$	
NDDCOP Network DUoS Demand Charge - Off Peak$	
NDDCP Network DUoS Demand Charge - Peak$	
NDKVAADC Network DUoS kVA Actual Demand Charge$	Revenue from Measured Maximum Demand Charges
NDERPC Network DUoS Excess Reactive Power Charge$	
NDVC Network DUoS Volume Charge$	Revenue from Energy delivery charges where time of use is not a determinant
Residential and Business Inclining Block Tariff Band1$	

Methodology for DCOS specific issues

Revenue from controlled load customer charges (DREV0106), DREV0112 and Revenue from unmetered supplies (DREV0107) are inclusive of Fixed Charges and Volume charges i.e.: these charges haven't been separately reported in Revenue from Fixed Customer Charges (DREV0101) or Revenue from Energy Delivery charges where time of use is not a determinant.

For Revenue from Contracted Maximum Demand charges (DREV0108) and Revenue from Measured Maximum Demand charges (DREV0109), Ergon Energy has allocated the full recovery of revenue from customers on the SAC - Large tariff to Contracted Demand. Revenue from

Demand component of Seasonal Time of Use Demand tariffs has also been allocated to

Contracted Demand. Ergon Energy has adopted this approach as it is consistent with the approach used for Template 3.4 Operational data, 'Demand supplied' where instructions state, where Ergon Energy cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.

Methodology for Table 3.1.1 & 3.1.2

Revenue from Public Lighting (DREV0112) has been reported as either ACS or SCS based on its service classification for the regulatory control period.

Variables (DREV0101 - DREV0109, and DREV0112) have been adjusted from the billed amounts (with the basis above) to an unbilled basis. The adjustment is an alignment with the reporting in Ergon Energy's 2019-20 Annual Reporting RIN. The total at DREV01 using AR RIN (on an unbilled basis) is higher than the sum of the variables using the billed basis. The difference has been allocated on a pro rata basis over the variables listed above.

DREV0110 - Metering Charges:

- SCS is zero for 2019-20. All Metering is ACS in 2019-20
- ACS for 2019-20. The revenue is taken directly from the Income Statement in Ergon Energy's 2019-20 Annual Reporting RIN.

DREV0111 - Connection Charges:

- SCS for 2019-20. This revenue is taken directly from the Income Statement in Ergon Energy's 2019-20 Annual Reporting RIN. It is the Contributions in SCS.
- ACS for 2019-20. This revenue is taken directly from the Income Statement in Ergon Energy's 2019-20 Annual Reporting RIN. It is the total of the Connection services column.

DREV0112 - Public Lighting:

- SCS for years 2019-20. Ergon Energy has sourced information from PEACE monthly billing reports.
- ACS for 2019-20. The revenue has been taken directly from the Income Statement in Ergon Energy's 2019-20 Annual Reporting RIN. It is the total of the Public Lighting column.

DREV0113 - Revenue from Other Sources:

- SCS, nothing to report.
- ACS for 2019-20. The revenue has been taken directly from the Income Statement in Ergon Energy's 2019-20 Annual Reporting RIN. It is the total of the Ancillary network services column.

Variables DREV0110, DREV0111, DREV0112 (ACS), DREV0113, and DREV01, are derived from Ergon Energy's 2019-20 Annual Reporting RIN. No adjustment is required for an unbilled basis, as the AR RIN has been prepared on an unbilled basis. Variable DREV0112 (SCS) has been adjusted from a billed basis to an unbilled basis.

Capital Contributions have been recorded as 'Revenue from Other Customers' in Table 3.1.2 'Revenue grouping by customer type or class' as opposed to the customer type variables set by the AER. Unlike DUOS revenue which can be allocated to customer type variables based on network tariff codes (refer above); Contributions don't have a secondary system to verify the customer classes to allow mapping to these categories. Therefore, Ergon Energy has adopted the approach in the Instructions and Definitions document which states:

- Revenues that Ergon Energy cannot allocate to the customer types DREV0201-DREV0205 must be reported against 'Revenue from other Customers' (DREV0206).

Methodology for Table 3.1.3

The STPIS reward (DREV0302) has been calculated based on data in the TAR formula in the

2019-20 Pricing Proposal. Consistent with advice received from the AER on 15 May 2019,

to reflect Ergon Energy's underlying performance results data has been based on STPIS reward implicitly included in revenues for pricing (i.e. s factor prior to removing prior years factor impact).

The EBSS payment (DREV0301) has been calculated based on data in the AER's Final Determination SCS PTRM. This was the PTRM used to set prices from 2019-20.

The EBSS payment has been reconciled against data included in Attachment 1 of the AER's final determination.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided actual information, in accordance with the AER's definition.

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

Ergon Energy commenced accrual accounting for Network charges in 2013-14, and continued in 2019-20. The impact of the change is a 0.3% decrease to DREV01 & DREV02 as a result of the net impact of accruals.

No accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice, in relation to variables contained in template 3.1, table 3.1.3.

AASB 15 Revenue from Contracts with Customers has replaced AASB 118 Revenue.

There were no changes to the revenue recognition policies for the major income streams (Network Use of Systems (NUOS) revenue, retail energy sales, sale of goods, the majority of contracts for services, operation, maintenance and construction of network assets and the non-refundable capital contributions) as a result of the requirements of the new standard.

Refer to Note 2 in the Statutory accounts for more detail on the revenue streams impacted by the new standard.

Table 3.1.2 - Revenue Grouping by Customer Type or Class 2

Compliance with the RIN Requirements

Revenue from Non-residential low/ high voltage demand tariff customers

Distribution Loss Factor is allocated to all connections based on where they sit in the network. This data is used in actual billing.

Sources

Revenue from Non-residential low/ high voltage demand tariff customers

Data Source is PEACE monthly billing reports which include allocated Distribution Loss Factors

Methodology

Revenue from Non-residential low/ high voltage demand tariff customers

For 2019-20, Ergon has used the allocated Distribution Loss Factor to distinguish connections between High and Low voltage, as it believes it is more accurate than previous system. It is also easily repeatable and consistent year to year.

Previously Ergon assigned all SAC Level customers to Low Voltage except for a set of customers that were previously assigned to a now defunct tariff of SAC Demand High Voltage. We were therefore unable to identify any new connections at High Voltage.

Monthly billing reports are summed by Distribution Loss Factors, LV Bus and LV Line levels to Low Voltage

Assumptions

Revenue from Non-residential low/ high voltage demand tariff customers

Ergon has assumed there are very few connections in the range 415v to 1,000v.

Estimated Information

Revenue from Non-residential low/ high voltage demand tariff customers

DREV0203 and DREV0204: Data splitting High /Low voltage in table 3.1.2 is considered estimated.

Ergon Energy defines Low voltage below 1,000v; this report defines Low voltage as 415v or below.

Ergon Energy does not have systems which can relate billing system data to actual voltage level

(i.e. which distinguishes between 415v and up to 1,000v). We have used allocated Low Voltage Distribution Loss Factor as there will be very few (if any) connections between 415v and 1,000v

Explanatory Notes

Revenue from Non-residential low/ high voltage demand tariff customers

Ergon Energy is working to identify and quantify connections between 415v to 1,000v for future reporting.

BOP - 3.2 Operating Expenditure

Table 3.2.1 - Current OPEX Categories and Cost Allocations

Table 3.2.2 - OPEX Consistency - Current Cost Allocation Approach

Compliance with the RIN Requirements

Variables DOPEX0101 - DOPEX0110 (and subsequently, total DOPEX01) are considered mandatory and have been populated.

Variables DOPEX0101 - DOPEX0103 have been assigned a category name. Variable DOPEX0104—DOPEX0110 represent additional variables (rows) inserted for other Opex categories as required by Ergon Energy and allowed for under the RIN Instructions and Definitions.

Ergon Energy confirms, as required by AER in Box 2, Reporting Framework - Table 3.1.1 Current Opex categories and allocations in its Instructions and Definitions that Opex has been prepared in accordance with Ergon Energy current approved AER Cost Allocation Method (CAM). Directions within the Annual Reporting Requirements for the most recently completed RIN as submitted to the AER have been applied.

Opex has been reported in accordance with the categories required by the AER's RIN.

Ergon Energy does not currently own, control or operate any dual-function assets for inclusion in Opex. Ergon Energy does not have any subsidiaries which provide operating and maintenance services to the DNSP therefore reporting of margins are not applicable.

Where relevant (namely, during the current regulatory control period), total Opex equals that reported against the Annual Reporting Requirements (AER defined term) provided to the AER.

Variables DOPEX0201 - DOPEX0206 are considered mandatory, and have been populated.

Ergon Energy confirms, as required by the AER in Box 4, Reporting Framework - Table 3.2.1

Opex Consistency - Current Cost Allocation Approaches in its Instructions and Definitions that

Opex has been prepared for the 2019-20 financial year in accordance with Ergon Energy's current

AER CAM. For clarity, the AER Classification of Services per the current regulatory control period (2015-20) as referenced in that CAM have been applied for Opex tables 3.2.2.

Opex has been reported in accordance with the categories required by the AER's RIN.

Opex for transmission connection point planning is considered a Network Service as it is an activity involved in planning the network. This amount has not been included under variable DOPEX0201:

Opex for network services however has been included separately in variable DOPEX0206: Opex for transmission connection point planning, resulting in only one count of this amount in Table 3.2.2.

Sources

Ergon Energy has sourced the data used to populate template 3.2, table 3.2.1 and table 3.2.2 from the CAM Recast data extract 0295 Account Balances report for the current year.

Methodology

Using codes contained within the CAM Recast data extract mapped to AER reporting categories, for example: Activity 52130 (Preventative Meters) is mapped to variable Preventive Maintenance. This is the same mapping process adopted for reporting the Annual Reporting RINs.

Ergon Energy has sourced data from the CAM Recast data extract, created a Table containing mappings between the Activities and product codes to the EB RIN Variables (DOPEX0201 - DOPEX0206) and a query was run to extract costs against relevant variables. Consistent with last year's methodology, ancillary service costs has not been reported in the ACS column for Network Services as it does not meet the definition of Network Services.

Transmission Point Planning contained in template 3.2, table 3.2.2.

Actual Information for DOPEX0206 Opex for transmission connection point planning has been prepared using actual hours worked and the number of staff involved in meetings to arrive at on costs, and travel and accommodation costs.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) for 2019-20 in relation to all variables.

Explanatory Notes

The AER approved Ergon Energy's CAM in July 2014, effective from the 1 July 2015, introducing changes compared to the prior CAM primarily for the following:

- Reclassification of services (AER FDD Attachment 13) from SCS to ACS, predominately for Real Estate Developments and Type 5 & 6 Metering; and
- Redundancies are recognised as Regulated Opex costs.

The AER approved a subsequent change to Ergon Energy's CAM in November 2018, effective from the 1 December 2018, for a change in circumstance for corporate and organisational structure, and the accountability for the CAM. The methodologies for attributing and allocating costs remained unchanged.

Table 3.2.4 - OPEX for High Voltage Customers

Compliance with the RIN Requirements

DOPEX0401 is considered a mandatory variable and has been populated.

It is noted that data in this table will not reconcile to information reported in response to Annual Reporting RINs provided by Ergon Energy, as we do not capture costs in relation to distribution transformers owned by HV customers.

Sources

Ergon Energy has sourced the data from Ellipse using Ellipse Financials reflected into CA RIN Template 2.8 2019-20 for actual costs for distribution maintenance.

Variable DPA0502: Distribution transformer capacity owned by High Voltage Customers (MVA) was also used in arriving at an estimate (refer to Table 3.5.2 Transformer Capacities Variables for a detailed explanation of the source for the data).

Methodology

Refer response to below, which details the methodologies applied to provide Estimated Information including assumptions made.

Assumptions

No assumptions were made.

Estimated Information

Accordingly, Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to DOPEX0401 - Opex for High Voltage Customers.

On page 22 of the Instructions and Definitions document issued by the AER in November 2013, it states

"When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for the Variables in Table 3.4 [renamed table 3.2.4] it must do so; otherwise Ergon Energy must provide Estimated Information."

As required by the AER's instructions and definitions, DOPEX0401 was estimated based on the

Opex Ergon Energy incurs for operating similar Megavolts-ampere (MVA) capacity Distribution Transformers within its own network.

The total annual cost of maintenance for distribution transformers (owned by Ergon Energy) was obtained for 2019-20 from Ellipse. The total annual maintenance cost for distribution transformers owned by Ergon Energy was then multiplied by the percentage of Ergon Energy's distribution transformers greater than 500kVA capacity to obtain the annual maintenance cost of >500kVA transformers owned by Ergon Energy. The annual maintenance cost of the >500kVA transformers owned by Ergon Energy was then divided by the total MVA of the >500kVA transformers owned by Ergon Energy to give the per-MVA cost of maintaining Ergon Energy owned transformers >500kVA.

There are no customers below 500kVA and connection policies have freed up conditions regarding HV customers such that some are now connected with as low as 500kVA capacity requirements, versus a previous minimum of 1,000kVA, making 500kVA a suitable delineating point. Therefore, the cost of maintenance for Ergon Energy's transformers above 500kVA was calculated. HV Transformer capacity owned by Customers (MVA) was multiplied by the per-MVA cost ($/MVA) of maintaining Ergon Energy owned transformers > 500kVA to provide an estimate of the cost of maintaining the distribution transformers owned by customers. Base year for Distribution Transformer numbers is 2019-20.

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

Changes in accounting policies adopted by Ergon Energy are not relevant to costs incurred in relation to external customers, other than in relation to components of data being utilised for the estimate provided (that is, Opex).

Costs have been presented on a current cost approach basis in that it is consistent with the most recent Annual Reporting Requirements and the 2019-20 allocation of costs in the CAM.

BOP - 3.2.3 Provisions

Table 3.2.3 - Provisions

Compliance with the RIN Requirements

Variables considered mandatory have been populated, relative to each Provision.

Ergon Energy confirms, as required by the AER in Box 6, *Reporting Framework for Provisions* in its RIN Instructions and Definitions, that provisions are reported in accordance with the principles and policies within the Annual Reporting Requirements (AER defined term) for the Regulatory Year.

Furthermore, financial information on provisions reconciles to the reported amounts for provisions in the annual RIN or Regulatory Accounts information provided to the AER.

Ergon Energy notes that the AER has changed the variable numbers associated with this table in its revised templates in the past. While this is the same format as 2013-14, care should be taken when reviewing variable data for 2019-20 against prior submissions.

Sources

Data has been sourced from the Ergon Energy general ledger. CAM re-forecast data has been used to calculate the Capex/opex split

Methodology

The balances in L3600 - Restructuring, L3800 - Long Service Leave, L3810 Annual Leave, L3820 Vested Sick Leave, L7000 Prov for Long Service Leave NC and L7010 Prov for Annual Leave NC will now be swept to EQLD on a monthly basis via a reversing accrual journal. We will continue to report on these activities in this and future EB Provision submissions to reflect the movements in these activities.

As discussed with the AER - On 1 July 2019, employees of the distribution network service providers Ergon Energy and Energex where transferred to Energy Queensland Limited (EQL) as the parent entity of the Energy Queensland Limited corporate group. EQL has entered into the Service agreement with Ergon Energy and Energex which effectively provides Energex and Ergon Energy with a labour resource and this is subject to the direction and management of the DNSP's. Therefore, labour provided under the EQL service agreement is reported as in-house/internal labour, and not reported as outsourced labour. Furthermore, employee related provisions no longer reside with the DNSP's - they reside with EQL. Balance sheet balances were transferred to EQL on 30 June 2019.

The closing balance of employee related provisions is therefore zero. The transfer to EQLD has been reflected in 'unused amounts reversed during the period-other component'. It is noted that movement in provisions is reflective of EQL employees whose payroll was processed in the Energex/Ergon Energy ERP system. The movement in the EQL provisions (which represents employees whose payroll was processed in the EQL ERP system) has been apportioned between the two DNSP's on a 50/50 basis in line with how EQL were allocated to the DNSP's.

(1) The Restructure Provision has been calculated on the following basis:

- Increases to the Restructure Provision are deemed to be the redundancy provision of employees who are expected to leave the company on a voluntary redundancy basis;
- Used is deemed to be the redundancy provision for those employees whose employment with the organisation has been terminated and a redundancy payment has been made to the employee;
- Redundancy provision calculations are provided by Human Resources;
- The SCS portion is based on the service classifications split of the asset base.

(2) The Employee On Costs and the Super on Employee Entitlements Provision for Annual Leave and Long Service leave have no values in 2020 as those costs have now been directly costed to L3800 (Provision for Long Service Leave) and L3810 (Provision for Annual Leave).

(3) The segments for Vested Sick Leave, Employee On Costs and Super on Employee Entitlements have been removed from the Rosetta Template.

The SCS portion is based on the service classifications split of the asset base, then split between Opex and Capex using the actual Opex/Capex spend per the general ledger.

(4) The Rehabilitation Provision has been split as per classification of individual sites, i.e. regulated sites and non-regulated sites. The value of the movement has been allocated 100% to OPEX and nil to CAPEX to correctly reflect the activities used in the journal entries. If the movement in the Rehabilitation provision was due to Revalued assets, (i.e. posted to Asset Revaluation Reserve) this is classified as Other.

Unused amounts reversed during the period is calculated by taking the write back provisions (to opex) figure from the Rehabilitation TAB within the provisions workings workbook.

(5) Vested Sick Leave has been journaled to EQLD in 2020 on a permanent basis and therefore has a nil balance in EECL.

(6) The Long Service Leave Provision has been calculated using the payroll entries which represent leave taken by employees- these appear as debits on the Ellipse transaction listing as 'OR' in reference 4. These transactions are deemed to be used. The balance is then split between the time value of money and the increases derived from the Ellipse transaction listing. The time value of money is derived from the Long Service Leave calculation model using the corporate bond

rates and then the corporate bond rates are removed to derive the undiscounted value. The time value is then the movement from 30 June last year to 30 June this year.

Assumptions

The difference in PP&E allocation percentages between the current regulatory year and prior regulatory year is treated as follows:

- adjustments that resulted in increased provisions are assumed to be additions to provisions; and
- adjustments that resulted in decreased provisions are assumed to be unused amounts reversed.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 3, table 3.2.3 - Provisions.

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

There were no changes in accounting policies impacting Provisions during the 2019-20 year.

BOP - 3.3 Assets (RAB)

Table 3.3.1 - Regulatory Asset Base Values

Table 3.3.2 - Asset Value Roll Forward

Table 3.3.3 - Total Disaggregated RAB Asset Values

Compliance with the RIN Requirements

Asset Value Roll Forward - SCS and ACS

Ergon Energy confirms, as required by the AER in Box 7, *Assets (RAB) Financial Reporting Framework* in Appendix B, Instructions and Definitions, that:

- RAB financial information (capex, disposals and inflation) for SCS and ACS reconciles to decisions the AER has made in relation to RAB values for these services in the 2020-25 Ergon Energy Final Determination; and
- Where forecast values (additions and disposals) were used in relation to a decision on RAB values these amounts have been replaced with actual values which reconcile to amounts reported in the Annual Performance RIN for 2019-20.

Ergon Energy has adopted the *Standard Approach*, with *Direct Attribution to the AER's economic benchmarking RAB Asset Classes*, as described in section 4.1.1 of Appendix B, Instructions and Definitions. For some non-system assets to the AER's 'other long life assets' and 'other short life asset categories' their categorisation has been ascertained by using additional Ellipse source system extracts (additions report).

RAB Asset Financial Information for remaining asset classes has been directly allocated into RAB Asset categories in accordance with definitions provided in chapter 9 of the Appendix B, Instructions and Definitions. RAB values for each of the RAB Asset categories are exclusive of Capital Contributions.

Ergon Energy currently does not own, control or operate any Dual Function Assets

Although Variable Codes DRAB0801 - DRAB0807 in relation to RAB Asset 'Easements' are shaded orange, to allow for blacked out data input, these cells have been populated. Ergon Energy has the ability to report Easements, and necessarily they are not included in the remaining categories.

In accordance with the instructions and definitions, Ergon Energy has only included RAB values for those services where the AER has approved a RAB or RAB equivalent. Therefore, for ACS, Ergon Energy has only reported RAB assets that provide ACS Street lighting Services and Type 5-6

Metering Services, consistent with the classification of service, and the RAB that was approved for these categories of service in Ergon Energy's 2015-20 Distribution Determination. No RABs have been approved for any of Ergon Energy's other categories of ACS (Quoted and Fee Based Services).

Asset Value Roll Forward - Network Services

Ergon Energy has prepared the information for the Network Services RAB in accordance with the definition of Network Services set out in Appendix B, Instructions and Definitions. Further detail on how the information provided by Ergon Energy is consistent with the requirements and definitions of Network Services is discussed below.

Total disaggregated RAB asset values

The value reported for the total disaggregated RAB asset values in table 3.3.3 for each respective asset category is derived as the average of the opening value and closing value reported in table 3.3.2. As the RAB values for each of the asset categories in template 3.3 are exclusive of capital contributions a zero value has been reported in line item DRAB13. This is inconsistent with previously reported data. The interpretation of DRAB13 is that the amount to be reported is the amount which has been disclosed in the disaggregated value. As this amount is net of capital contributions then zero is the appropriate value to be reported. Previously reported amounts were incorrectly disclosed. As DRAB13 is a standalone disclosure line item the value reported has no implications on other information items within the RAB

Sources

Asset Value Roll Forward - SCS and ACS

For 2019-20, annual SCS and ACS (street lighting and Type 5-6 metering) financial information (additions, disposals and capital contributions) are sourced from the 2019-20 AER Annual Reporting RIN provided by Ergon Energy to the AER. Capex recognised in the SCS RAB and therefore reported in the T3.3 RIN Template is exclusive of capital contributions.

The 2019-20 estimated financial information contained within the AER's 2020-25 final Distribution Determination has been replaced with actual financial information for 2019-20 as reported in the 2019-20 Annual Performance RIN. The closing RAB values for each year from 1 July 2015 onwards will also not align with the closing RAB values calculated each year in the AER's 2015-20 RFM. This is because the AER's 2015-20 RFM recognises actual 2014-15 additions and disposals for the first time at the end of 2019-20, whereas in the T3.3 RIN template the actual 2014-15 additions and disposals is recognised in the year in which it is incurred, and rolled forward through to 1 July 2020.

Asset Value Roll Forward - Network Services

As defined by the AER for the purposes of the Economic Benchmarking RIN, Network Services are a subset of SCS excluding Connection Services, Type 5-7 Metering Services, Fee Based and Quoted Services and Street Lighting Services. Consistent with the AER's definition of Network Services it is also necessary to exclude gifted assets (since these are all related to connection services) and also any assets included in the Network Services category that are not funded by Ergon Energy i.e. Network Services funded via capital contributions.

Network Services data is derived from SCS data. 2014-15 to 2019-20 SCS actual additions and disposals are sourced from the 2014-15 to 2019-20 AER Annual Reporting RINs respectively, provided by Ergon Energy to the AER.

Consistent with the SCS RAB values reported in the T3.3. RIN Template, the reported actual SCS additions used in calculating the Network Services net capex for the 2019-20 regulatory year are consistent with the SCS values in the 2019-20 Annual Reporting RIN, adjusted for movements in provisions and shared asset usage.

Connection Services data is captured within the Ergon Energy "Connections" expenditure category. For 2019-20, the annual Connections expenditure values are sourced from the 2019-20 AER Annual Reporting RIN provided by Ergon Energy to the AER. Specifically, Connections expenditure includes:

- New shared network assets for Standard Asset Customers (i.e. small domestic, rural and customer customers);
- New dedicated connection assets for Standard Asset Customers; and
- Testing and commissioning of all new shared network assets and connection assets for Standard Asset Customers only.

It explicitly excludes metering expenditure, connection expenditure for real estate developers and design, construction, test and commission costs for large commercial and industrial customers.

Additionally, connections expenditure incorporates a portion of shared network expenditure (either funded by Ergon Energy or funded via capital contributions). To be consistent with the AER's definition of Network Services, it is necessary for any Ergon Energy-funded shared network to be reported in the Network Services category, but any gifted assets and shared network not funded by Ergon Energy to be excluded. In order to derive the net value of shared network expenditure to be included in Network Services (and hence, the value of Connections expenditure to be removed from the SCS asset additions), it is necessary to:

- Identify the total amount of Connections expenditure related to the shared network and to dedicated connection assets;

- Identify that portion of the Connections expenditure that is not funded by Ergon Energy (i.e. capital contributions).

The net result of the above (i.e. total Connections expenditure related to connection assets (i.e. not shared and not contributed by customers) represents that portion of Connections expenditure that is required to be removed from SCS asset additions in order to determine the amount attributable to Network Services.

Actual additions, disposals and capital contributions for 2019-20 associated with Type 5-6 Metering Services (to be removed from SCS data and hence Network Services data) are sourced from Ergon Energy's 2019-20 Annual Reporting RIN templates.

No adjustment is necessary in relation to Street Lighting, Fee Based and Quoted Services since this expenditure is already excluded from the SCS data (and hence Network Services data).

For 2019-20, the value of capital contributions (gifted assets and cash contributions) is sourced from the 2019-20 Annual Reporting RIN.

Total disaggregated RAB asset values

Data used to populate this table was extracted from the 2019-20 AER Annual Reporting RIN lodged by Ergon Energy to the AER.

Methodology

Asset Value Roll Forward - SCS and ACS

Template 3.3, table 3.3.1 (Regulatory Asset Base Values) requires Ergon Energy to report totals for RAB Financial Information for 2019-20, across Network Services, SCS and ACS.

Ergon Energy notes that variables DRAB0101 through DRAB0107 in table 3.3.1 represent RAB Financial Information for the total asset base. The RAB Financial Information for the total asset base is then further disaggregated into the lower level RAB Asset Categories for each category of service (SCS, ACS and Network Services) in table 3.3.2.

As Ergon Energy has addressed the Basis of Preparation requirements at the lower level RAB Asset Categories, it is implicit that Ergon Energy has also addressed the minimum requirements for template 3.3, table 3.3.1. This is because all of the RAB values set out in template 3.3 have been calculated using a common Roll Forward Model (RFM) for each category of service (SCS, ACS and Network Services). As a result, the RAB values reported for the total asset base in table 3.3.1 will be consistent with the RAB values reported at the lower level RAB Asset Categories in table 3.3.2 for each category of service.

Opening RAB Values

The opening SCS RAB as at 1 July 2019 has been amended to reflect the final decision for Ergon Energy Distribution Determination 2020-2025 RFM balance adjusted for actuals. Accordingly, the 2019 opening balance does not equal the 2018 closing balance as reported in the 2018/19 EB RIN.

To comply with the RAB decision as detailed in the 2020-25 Ergon Energy Final Determination, the SCS RAB balances for 2019-20 have been established by taking the existing balances incorporated within the RFM suite of models and making adjustments to reflect both the amalgamation of the legacy and capex RFMs into a singular RFM model, and the allocation of the under/over recovery of overheads to capital over the period 2015 to 2019 as approved by the AER.

As required the closing balances in the 2020-2025 Final Distribution Determination RFM has been adjusted to recognise 2019-20 actual capex and disposals.

To model the amalgamation of the RFMs, the opening balance for 2015-16 as reported in the Final Decision RFM after allowing for the difference between actual and forecast net capex in the prior reporting period (2014-15) was compared to the opening balances in the existing legacy and capex RFMs. The variance between these amounts at each individual asset class was adjusted by adding the difference to the legacy model opening balance for 2015-16.

The adjustment to capex balances for under/over recovery of overhead as identified in the Final Decision was made within the Capex RFM. The under/over recovery amount was included in the respective years to which it related. Under/over recoveries were reported for years 2015-16 to 2018-19.

For 2019-20 the asset roll forward balance has been amended to incorporate equity raising costs of$8.09M. This is a departure from previous reporting practices where equity raising costs have not been captured within the reported information of table 3.3.2. The result is that tables 3.3.1 and 3.3.2 now reconcile in total. It has been decided that the nature of equity raising costs falls within the asset class definition for reporting in table 3.3.2.

The opening ACS RAB as at 1 July 2015 in the 2015-20 RFM for ACS is set equal to the sum of the Type 5-6 Metering opening RAB value on 1 July 2015 as approved by the AER in the 2015-20 Final Distribution Determination, and the Public Lighting closing RAB in the 2010-15 RFM for ACS as calculated in cells L373 of the Total Actual RAB Roll Forward tab.

Straight Line Depreciation

Ergon Energy has reported straight line (and implicitly, regulatory depreciation) for 2019-20 as 'Actual Information'. This is because:

- The inflation of the opening RAB, which comprises part of the regulatory depreciation amount, is an actual value based on the escalation of the 2019-20 opening RAB by the actual 2019-20 inflation.
- The forecast 2019-20 straight line depreciation, which comprises the remainder of the regulatory depreciation amount, is also considered to be 'Actual Information', because:
  - The AER's email of 7 September 2016 requires that Ergon Energy report straight line depreciation in accordance with that forecast by the AER for 2019-20 in its 2015-20 Final Distribution Determination.
  - Ergon Energy has been directed by the AER to use forecast depreciation therefore there is no other valid alternative by which to report this information. Forecast depreciation is obtainable from the 2015-20 Final Distribution Determination, and the AER's FDD RFM. It is a record used in Ergon Energy's normal course of business for the purposes of reporting the RFM RAB that is not estimated or calculated by Ergon Energy as part of the EB RIN reporting process.

Other Matters

Ergon Energy asset categories (as reported in the SCS and ACS RFMs and Annual Reporting RIN's) have been directly mapped to the required economic benchmarking RAB asset categories, with the exception of some non-network asset categories (see below).

For some non-network asset categories (buildings, motor vehicles and plant and equipment), the AER definitions require Ergon Energy to split assets between short and long-life assets categories. Ergon Energy does not report data on this disaggregated basis. However, asset additions are readily determined from the asset register along with their lives. This information was used to apportion the relevant opening balances, additions and disposals to the required short and long-life categories.

Ergon Energy has apportioned total buildings, motor vehicles and plant & equipment attributable to short and long life categories on the basis of asset addition for each asset. Asset additions are readily determined from the asset register along with the associated asset lives. With motor vehicles (as an example) heavy vehicles and a % of total vehicle additions was determined. This was then used to split total vehicle Capex between short and long lives. The same process was used for buildings and for plant & equipment. RAB disposals are allocated between short and long life assets based on asset additions to these categories.

Asset Value Roll Forward - Network Services

Network Services is a subset of Standard Control Services (SCS), whereby certain assets (e.g connection services) are excluded from the SCS RAB to determine the Network Services RAB. Accordingly, network service balances will incorporate the changes to SCS RAB as reflected in the final Decision RFM outlined above.

Ergon Energy provides the following explanation of how connection services amounts are determined which are subsequently removed from SCS capex to derive the capex to be included in the network services RAB.

Connections Capital Expenditure is sourced from the general ledger, by asset class, from codes C2060 (domestic and rural connections), C2070 (small commercial and industrial connections) and C2080[1] (other) is pro-rated across both C2060 and C2070. Whilst these expenditures are exclusive of gifted assets and cash contributions, they are inclusive of both upstream shared network expenditure and dedicated connection asset expenditure.

To identify the upstream shared network expenditure component, the following approach is taken.

- The LV Services and Meters asset classes are removed from both the C2060 and C2070 capital expenditures. This is because these asset classes are always 100% dedicated connection assets.
- Then, the percentage of dedicated connection assets obtained from a sample of domestic and rural and small commercial and industrial connection projects is applied to the C2060 and C2070 capital expenditures respectively. This gives an indication of the upstream shared network component of the Connection Capital Expenditure that must be included in the total Network Services Capital Expenditure.
- The remainder of the Connection Capital Expenditure, together with the LV Services and Meters capital expenditure, is the dedicated connection asset capital expenditure that must be removed from the SCS Capital Expenditure.
- There is currently a known limitation to the percentage of dedicated connection assets for domestic and rural and small commercial and industrial connection projects. The calculations were derived using prior year samples which represented five percent of all connection works for domestic and rural and small commercial and industrial connection projects. These included projects which were entirely Ergon Energy funded, and those which involved capital contributions. Ergon Energy recognises that the samples should be taken only from projects that were entirely funded by Ergon Energy, as these percentages are applied to Connection Capital Expenditure from the general ledger that are exclusive of capital contributions. Given data limitations this is currently not possible.

Consistent with the SCS and ACS RIN values described earlier in this document, 2015-16 to 2019-20 inclusive network services additions and disposals are calculated (using the approach outlined above) based on actual SCS capex and disposal values. The value of disposals reflects gross proceeds of sales basis.

2015-16 to 2019-20 opening RAB, closing RAB, Inflation addition for network services are calculated based on the network services additions and disposal values in accordance with calculations within the RFM adopted by the AER in its Final Distribution Determination.

Opening RAB Values

Network Services is a subset of Standard Control Services (SCS), whereby certain assets are excluded from the SCS RAB to determine the Network Services RAB. In updating the SCS RAB for the Final Distribution Determination for 2020-2025 it was identified that a number of asset category balances for network services were in excess of the SCS RAB value. Where the respective asset category did not incorporate any connection service expenditure the network services asset category balance was adjusted to align with the reported SCS balance.

Further, through the updating process it was revealed that the network services RAB had inadvertently been understated with the removal of gifted assets being duplicated. In preparing the SCS RAB, all capital contributions are excluded from additions, in accordance with the RIN requirements, and therefore are excluded from the SCS RAB balances. In determining the Network Services RAB balances, the SCS RAB additions were reduced by removing contributions from the SCS additions. Given all contributions had been excluded from the SCS RAB, this resulted in an understatement of the Network Services additions and balances. The understatement of Network Services has occurred throughout the 2015-20 regulatory period. The cumulative impact on Network Services RAB additions throughout the period occurred as follows:

- 2015-16 - $10.5M
- 2016-17 - $2.1M
- 2017-18 - 15.9M
- 2018-19 - 44.2M
- 2019-20 - 59.6M
- Total - $132.3M

For 2019-20 the asset roll forward balance has been amended to incorporate equity raising costs $8.09M. This is a departure from previous reporting practices where equity raising costs have not been captured within the reported information of table 3.3.2. The result is that tables 3.3.1 and

3.3.2 now reconcile in total. It has been decided that the nature of equity raising costs falls within the asset class definition for reporting in table 3.3.2.

Other Matters

Ergon Energy asset categories (as reported in the SCS and ACS RFMs and Annual Reporting RINs) have been directly mapped to the required economic benchmarking RAB asset categories, with the exception of some non-network asset categories (see below).

For some non-network asset categories (buildings, motor vehicles and plant and equipment), the AER definitions require Ergon Energy to split assets between short and long-life assets categories. Ergon Energy does not report data on this disaggregated basis. However, asset additions are readily determined from the asset register along with their lives. This information was used to apportion the relevant opening balances, additions and disposals to the required short and long-life categories.

Ergon Energy has apportioned total buildings, motor vehicles and plant & equipment attributable to short and long life categories on the basis of asset addition for each asset. Asset additions are readily determined from the asset register along with the associated asset lives. With motor vehicles (as an example) heavy vehicles and a % of total vehicle additions was determined. This was then used to split total vehicle Capex between short and long lives. The same process was used for buildings and for plant & equipment. RAB disposals are allocated between short and long lived assets based on asset additions to these categories. The apportionment for Network Services is the same as that for SCS, and the apportionment of the ACS shared asset adjustment to the 2014-15 closing RAB values for buildings, motor vehicles and plant & equipment is also performed using the same method.

Total disaggregated RAB asset values

The value reported for the total disaggregated RAB asset values in table 3.3.3 for each respective asset category is derived as the average of the opening value and closing value reported in table 3.3.2. As the RAB values for each of the asset categories in template 3.3 are exclusive of capital contributions a zero value has been reported in line item DRAB13. This is inconsistent with previously reported data. The interpretation of DRAB13 is that the amount to be reported is the amount which has been disclosed in the disaggregated value. As this amount is net of capital contributions then zero is the appropriate value to be reported. Previously reported amounts were incorrectly disclosed. As DRAB13 is a standalone disclosure line item the value reported has no implications on other information items within the RAB

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term).

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

Refer to Basis of Preparation for Template 3. Opex, which will discuss any changes in accounting policies impacting capex or opex (if at all) for the regulatory year.

Asset lives reported are a non-financial data set, and accordingly changes in accounting policy do not impact it.

Table 3.3.4 - Asset Lives (estimated Residual Service Life)

Table 3.3.4 - Asset Lives (estimated Service Life of New Assets)

Compliance with the RIN Requirements

All data entry fields are shaded yellow, indicating mandatory data input fields and accordingly, have been populated.

Asset lives reported, are estimated service lives of new assets installed during the regulatory reporting year

Sources

Data was sourced from Ergon Energy's fixed asset register. Asset lives in the fixed asset register are based upon engineering expectations and are reviewed on a regular basis.

Methodology

Asset Lives

- Asset lives - Ergon Energy has adopted the standard and remaining lives for SCS and ACS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2010 in the respective 2010-15 RFMs. Similarly, Ergon Energy has also adopted the standard and remaining lives for SCS and ACS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2015 in the respective 2015-20 RFMs.
- Asset lives - For Network Services, Ergon Energy has adopted the standard and remaining lives for SCS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2010 in the respective 2010-15 RFMs. Similarly, Ergon Energy has also adopted the standard and remaining lives for SCS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2015 in the respective 2015-20 Network Services RFMs.

Asset Lives - Estimated Service Life of New Assets

A mapping exercise was applied to data obtained from the fixed asset register whereby data was grouped into the RAB Asset categories required by the AER, in accordance with category definitions provided in Chapter 9.

Where RAB Asset categories contained assets of differing lives, a weighted average estimated life was calculated based on replacement cost using the formulae prescribed by the AER (equation 1, weighted average asset life calculation).

Asset Lives - Estimated Residual Service Life

A mapping exercise was employed on data obtained from the fixed asset register whereby data was grouped into the RAB Asset categories required by the AER, in accordance with category definitions provided in Chapter 9.

Where RAB Asset categories contained assets of differing lives, a weighted average estimated life based on replacement cost was calculated using the formulae prescribed by the AER (equation 1, weighted average asset life calculation).

When assessing straight line depreciation for the RAB in Template 3.3 (Assets), the depreciation is based on remaining asset lives from the AER's 2015-20 Final Determination for Ergon Energy.

Ergon Energy submitted two separate RFMs (a "Legacy" RFM and a "Capex" RFM). The Legacy RFM relates to assets existing before 1 July 2010, while the Capex RFM relates to assets acquired over the 2010-15 regulatory control period. The closing RAB values as at 30 June 2015 from each RFM were then combined to give the opening RAB values as at 1 July 2015, as used in the PTRM for the 2015-20 regulatory control period. Rolling forward the 1 July 2010 RAB in the Legacy and Capex RFMs was done to more accurately calculate the weighted average remaining life as at 1 July 2015 and in turn produce a more accurate depreciation calculation for the purposes of calculating SCS revenues in the 2015-20 regulatory control period. This approach was approved by the AER in its 2015-16 Final Distribution Determination for Ergon Energy.

The residual service lives for the purposes of reporting Table 3.3.4 have been populated in accordance with Template requirements using lives from Ergon Energy's fixed asset register. The table does not reflect the more refined asset life segregation between pre 1 July 2010 and post 30 June 2010 purchases as approved by the AER. Therefore, caution should be taken when assessing depreciation expense in relation to remaining asset lives reported in Table 3.3.4.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 4, table 3.3.4 (Asset Lives).

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

Refer to Basis of Preparation for Template 3. Opex, which will discuss any changes in accounting policies impacting capex or opex (if at all) for the regulatory year.

No accounting policies adopted by Ergon Energy have impacted on capital contributions received.

Asset lives reported are a non-financial data set, and accordingly changes in accounting policy do not impact it.

BOP - 3.4 Operational Data

Table 3.4.1 - Energy Delivery

Compliance with the RIN Requirements

All entry fields are shaded yellow indicating mandatory data fields, and accordingly have been populated.

Table 3.4.1 - Energy Delivery Energy Delivery

DOPED01 entry fields shaded yellow, indicating mandatory data fields have been populated.

Total Energy Delivered reported is the total metered or estimated energy delivered at the customer charging locations (rather than the import location from the TNSP).

Energy Grouping - Delivery by Chargeable Quantity

Entry fields shaded yellow, indicating mandatory data fields have been populated.

'*Energy Delivered where time of use is not a determinant'* (DOPED0201) relates only to energy delivered that was not charged for peak, shoulder or off-peak periods. This heading includes the Bands from Inclining Block tariffs.

Ergon Energy's Time of Use tariffs include Peak and Off-Peak only, and actual results are shown.

This is consistent with the AER's clarification received on 28 April 2015 which stated that where Ergon Energy does not charge for energy delivery on a peak, off peak or shoulder basis then zeros should be entered against these variables in table 3.4.1.1.

Energy Received from TNSP and Other DNSPs by time of Receipt

'*Energy Received from TNSP and other DNSPs not included in the above categories'*

(DOPED0304) relates only to energy received that was unable to be allocated to peak, shoulder or off-peak periods.

In this regard, a wholesale time of use schedule does not exist as relevant to Energy Received. Accordingly, no disaggregation has been provided for time of use variables (DOPED0301-DOPED0303).

This is consistent with the AER's clarification received on 28 April 2015 which stated that if Ergon Energy is not billed for energy it receives on a peak, off peak or shoulder basis then zeros should also be entered against these variables in table 3.4.1.2.

Energy Received into DNSP system from Embedded Generation by Time of Receipt

'*Energy Received from embedded generation not included in above categories from nonresidential embedded generation* (DOPED0404) relates only to energy received that was unable to be allocated to peak, shoulder or off-peak periods.

In this regard, a wholesale time of use schedule does not exist in relation to Energy Received. Accordingly, no disaggregation has been provided for time of use variables DOPED0401-DOPED0403.

Similarly, data for variables DOPED0405 - DOPED0407 in relation to energy received from Embedded Generation (residential) has not been recorded by Ergon Energy and accordingly, has been entered as '0'.

This is consistent with the AER's clarification received on 28 April 2015. In this clarification, the AER stated if Ergon Energy is not billed for energy it receives on a peak, off peak or shoulder basis then zeros should also be entered against these variables in table 3.4.1.3.

All other entry fields shaded yellow indicating mandatory data fields, have been populated.

Energy received from embedded generation not included in above categories from residential embedded generation (DOPED0408) has been populated.

Energy Grouping - Customer Type or Class

Ergon Energy confirms the category breakdown is consistent with the customer types reported in Table 3.4.2.1 Customer numbers, with the exception that Other Customer Class Energy Deliveries includes unmetered energy delivered (which in table 3.4.1.4 is separately reported for customer numbers).

Sources

TABLE 3.4.1 - ENERGY DELIVERY

Energy Delivery & Energy Grouping - Delivery by Chargeable Quantity

For year 2019-20, data has been sourced from Ergon Energy's billing system PEACE. Monthly billing reports, based on Statement of Charges monthly periods, are collated to provide actual data required.

Energy Received from TNSP and Other DNSPs by time of Receipt

Source is TNSP (PLQ) monthly billing files which are checked to metering data from Meter Data Agents (MDAs) and DNSP (Energex) monthly billing files. These billing files are checked to data from MDA.

Energy Received into DNSP system from Embedded Generation by Time of Receipt

Energy data for non-residential generators was sourced by Ergon Energy from National Electricity Market (NEM) settlements metering. All meters are interrogated by AEMO accredited MDAs and passed to Ergon Energy LNSP in accordance with Chapter 7 of the NER.

This data is automatically stored in the Ergon Energy DNSP central data repository - Network Optimisation Data Warehouse (NODW) for analysis by the various Ergon Energy Asset Development planning groups.

An aggregate load measurement point (LMP) was setup to cater for requirements, based on a new system. Only the energy received channel (B) is used in the aggregation. This aggregate LMP is updated when new and replacement measured data has been received and updated when the tool is accessed. The aggregate definition is maintained, as is all Ergon Energy aggregate LMPs, in line with new installations of embedded generation impacting on the Ergon Energy network.

Data for a very small number of Embedded Generators with low Generation Output (kW) is collected from NEM12 files and PEACE where required. This is impacted by the type of Meter and the type of data that each Meter captures

DOPED0408 (residential) data was sourced from the network billing system (PEACE), using a Network Tariff Code specific to residential Embedded Generation. Data is inclusive of all market customer premises supplied by Ergon Energy. (ISO areas not including Mt Isa were not included in these figures).

Energy Grouping - Customer Type or Class

For year 2019-20, data has been sourced from Ergon Energy's billing system PEACE. Monthly billing reports based on Statement of Charges monthly periods, are collated to provide actual data required.

Note: these sources were adopted also for Template 3.1, table 2.2 Revenue Grouping by customer class or type.

Methodology

Table 3.4.1 Energy Delivery Energy Delivery & Energy Grouping - Delivery by Chargeable Quantity

Ergon Energy employed a methodology whereby kWhs for energy delivery were summated from monthly billing data files into annual totals. As the source file captured data in kWhs the results were converted to GWhs.

Energy Received from TNSP and Other DNSPs by time of Receipt

Energy delivered to the Mount Isa distribution network (which includes Cloncurry but not the 220kV connected Carpentaria Mineral Province mines) is included in this aggregation given derogations which include this as part of the AER-regulated Ergon Energy regulated network. There is no TNI in any Australian Energy Market Operator (AEMO) documentation servicing this area of the network.

Energy Received into DNSP system from Embedded Generation by Time of Receipt

Energy received in to the network from larger installations of embedded generation is recorded on a half hour basis.

DOPED0408 (residential) data represents the sum of all KWh recorded with a Network Tariff Code specific to Embedded Generation with a Residential Customer Classification Code, from the PEACE data source.

Energy Grouping - Customer Type or Class

The disaggregation for all variables is based on actual data. High/low classification is now based on DLF code,

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term)

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.4.2 - Customer Numbers

Compliance with the RIN Requirements

Table 3.4.2 - Customer Numbers Distribution Customer Numbers by Customer Type or Class

Ergon Energy confirms the category breakdown is consistent with the customer types reported in Table 3.4.1.4 Energy grouping - customer type or class (refer section above), with the exception that Unmetered customer numbers are reported separate to "Other Customer" class (in table 3.4.1.4 they are combined as 'other).

'Other Customer Numbers' (DOPCN0106) was utilised only where customers were unable to be allocated to the other customer classes.

Distribution Customer Numbers by Network Location

All entry fields are shaded yellow indicating mandatory data fields, and accordingly have been populated, with the exception of 'DOOPCN0201' for CBD Network - Ergon Energy does not have any feeders classified as CBD.

Ergon Energy notes that DOPCN02 does NOT reconcile to DOPCN01 in Distribution Customer Numbers by Network Location, given DOCPN01 includes transmission or unknown (unclassified) feeder classes. No category was provided for these customers in DOPCN0201-DOPCN0204.

Sources

Table 3.4.2 - Customer Numbers Distribution Customer Numbers by Customer Type or Class

Ergon Energy Network has sourced customer numbers data for the start of the period and for the end of the period from the Peace system. Counts are of unique National Metering Identifiers (NMIs) that are identified as having Ergon Network as their DNSP.

Distribution Customer Numbers by Network Location

Ergon Network has sourced customer numbers data from the Market Transaction system (Peace). Counts are of unique NMIs that are identified as having Ergon Energy as their LNSP.

Methodology

Table 3.4.2 - Customer Numbers Distribution Customer Numbers by Customer Type or Class

Distribution Customers represent the average number of active NMIs in the network the relevant regulatory, calculated as the average number of NMIs on the first day of the regulatory year and on the last day of the regulatory year. Of note:

- Each NMI has been counted as a separate customer;
- Both energised and de-energised NMIs are counted; and
- Extinct and Greenfield site NMIs are excluded.

Residential data is identified by the NMI Customer Classification Code (CCC). Voltage & Demand splits were identified by the Network Tariff Types, whilst the Unmetered premises were identified by the NMI numbering range.

For Unmetered customers, excludes public lighting connections (also identified by the NMI numbering range). Unmetered energy usage for billing purposes is calculated using an assumed load profile.

Ergon Energy is still recording a sizeable increase in the unmetered customers as the National Broadband Network rollout continues to add a large amount of Unmetered Supplies to our network also.

Distribution Customer Numbers by Network Location

Distribution Customers represents the average number of active NMIs in the network, calculated as the average number of NMIs on the first day of the regulatory year and on the last day of the regulatory year. Of note:

- Each NMI has been counted as a separate customer;
- Both energized and de-energised NMIs are counted; and
- Extinct and Greenfield site NMIS are excluded.

In order to disaggregate data by feeder types (Urban, Short Rural and Long Rural), a NMI was identified as being attached to a feeder which in turn enabled the identification of the required feeder classes.

Assumptions

No assumptions were made.

Estimated Information

Not applicable. Ergon Energy has provided actual information.

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.4.3 - System Demand 1

Compliance with the RIN Requirements

Table 3.4.3 - System Demand

Annual System Maximum Demand (Zone Substation) (MW)

Variables DOPSD0102, DOPSD0103, DOPSD0105 and DOPSD0106 have been populated. All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Annual System Maximum Demand (Transmission Connection Point) (MW)

The orange cells associated with Variable Codes DOPSD0108, DOPSD0109 and DOPSD0111 and DOPSD0112 have been populated.

Annual System Maximum Demand (Zone Substation) (MVA)

The orange cells associated with Variable Codes DOPSD0202, DOPSD0203 and DOPSD0205 and DOPSD0206 have been populated.

Annual System Maximum Demand (Transmission Connection Point) (MVA)

The orange cells associated with variable DOPSD0208, DOPSD0209 and DOPSD0211 and DOPSD0212 have been populated.

Sources

Table 3.4.3 - System Demand

Annual System Maximum Demand

Data has been sourced from Substation Investment Forecasting Tool (SIFT).

The SIFT database is maintained for producing network demand forecasts of zone and bulk supply substations as well as Transmission Connection Points (TCPs). Access to the environment is secure and provided only to those persons who require access to conduct and manage the load forecasting process, and planning studies, with any changes to the datasets tracked and recorded.

The database is updated annually with substation demand data from the Network Operational Data

Warehouse (NODW) previously the variables were stored in the Statistical Metering Database (SMDB). Network Element Time Series Metering Tool (NETS) accesses the NODW and stores load information on network assets.

Methodology

Table 3.4.3 - System Demand

Annual System Maximum Demand (Zone Substation) (MW)

In order to obtain Weather-adjusted variables, Ergon Energy has employed the following methodology:

- Constructed a multivariate maximum demand equation for each season of Summer or Winter. Variables in the equation include maximum temperature, minimum temperature and variables for Saturday, Sunday and public holidays.
- Daily historical BOM temperatures are passed through each equation and maximum annual demand is obtained. The listing of annual peak demand is made for all set of consistent temperature records from each associated weather station.
- 50 POE and 10 POE measured from histogram of annual peak demands.

Annual System Maximum Demand (Transmission Connection Point) (MW)

In order to obtain Weather adjusted variables, Ergon Energy has employed a methodology involving:

- Constructed a multivariate maximum demand equation for each season of Summer or Winter. Variables in the equation include maximum temperature, minimum temperature and variables for Saturday, Sunday and public holidays.
- Daily historical BOM temperatures are passed through each equation and maximum annual demand is obtained. The listing of annual peak demand is made for all set of consistent temperature records from each associated weather station.
- Weather station selected by referral to associated Zone Substation weather station. Where a transmission connection point has multiple Zone Substations attached, the most common weather station is selected for the transmission connection point weather correction.
- 50 POE and 10 POE measured from histogram of annual peak demands.

Annual System Maximum Demand (Zone Substation & Transmission Connection Point) (MVA)

Weather adjustment MVA data have been obtained by multiplying raw MVA by the ratio of (MW temperature adjusted value to raw MW value) for the same regulatory year.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term)

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy

Table 3.4.3 - System Demand 2

Compliance with the RIN Requirements

Table 3.4.3 - System Demand

Power Factor Conversions (Overall Network)

DOPSD0301 is shaded yellow indicating a mandatory data field, and has been populated.

Power Factor Conversions (Remaining Voltage Levels)

Where variables are not relevant to Ergon Energy, these have not been populated. Where actual values were not available but a derived power factor is offered for an item this is taken as an appropriate estimate.

Sources

Table 3.4.3 - System Demand

Power Factor Conversions

Ergon Energy extracted power factor (pf) data from the Ergon Energy DNSP central data repository (NODW), which extracts this information from metering units across a significant proportion of Zone Substations over half hourly intervals. Where the measured/metered apparent (kVA) and real power (kW) value are obtained from NODW and power factor is derived as follows:

Power Factor = Real Power / Apparent Power

In the absence of metered real and apparent power data, the NODW power factor derivation is sourced (where available). In the absence of any metered data sources these line assets are ignored.

Methodology

Table 3.4.3 - System Demand

Power Factor Conversions (Overall Network)

DOPSD0301 '*average overall power factor conversion*' is required to represent the total MW divided by the total MVA.

The overall network power factor was derived from a coincident summation of kW and kVA at all the transmission network connections points (native) in the Ergon Energy network, with the peak demand power factor calculated from this data set at the time of the native system maximum demand.

DOPSD0301 = DOPSD0110 / DOPSD0210

where

DOPSD0110 - Coincident Raw System Annual Maximum Demand (MW) {Provided by Forecasting}

DOPSD0210 - Coincident Raw System Annual Maximum Demand (MVA) {Provided by Forecasting}

Power Factor Conversions (Remaining Voltage Levels with the exception of DOPSD0308 Average power factor conversion for 22 kV lines)

The key data is sourced from NODW, categorised according to Table 3.4.3.5, and calculated to obtain totals. Basic data cleansing was performed by eliminating all feeders with peak power factors less than 0.4 and substantially greater than 1 after extraction from NODW.

Some volatility exists for the power factor calculations and metering sources for 3.3kV, 6.6kV and SWER lines as these have very small asset populations or are not metered and require examination of their upstream sources, hence significant trending variations for 2019-20 are considered to be within tolerance.

In addition, it is noted that the current data source of NODW replaces the former SMDB (database) and associated toolsets such as FME workbench, which is capable of utilising many other data sources. Hence, power factor ratings of both the 11 and 22kV lines will not necessarily flow in-line with previous historical trends.

Assumptions

Assumptions:

- NODW database has a comprehensive asset population and is the true source of data procurement,

- NODW meter readings during the co-incident peak that report a power factor smaller than 0.4 are ignored as meter misreadings,

- NODW meter readings during the co-incident peak that report a power factor marginally above 1.0 are assumed to be within tolerance of the meter reading

- Where NODW meter readings for kW and kVAs values were not available, but derived power factor measured were then these alternative datasets were taken into account as substitutes.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term).

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.4.3 - System Demand 3

Compliance with the RIN Requirements

Table 3.4.3 - System Demand

Demand Supplied (for Customers Charged on this Basis) (MW)

All entry fields are shaded yellow indicating mandatory data fields however it is noted in the RIN that population is only required where Ergon Network charges customers for Maximum Demand supplied.

In instances where Ergon Network cannot distinguish between contracted and measured Maximum Demand, demand supplied was allocated to contracted Maximum Demand. This includes a large amount of customers on the Threshold Demand tariff.

Ergon Network commenced charging customers on a kVA (MVA) basis as of 1 July 2015. Customers are still being migrated from the kW tariffs to these newer kVA tariffs as is evident in the numbers reported.

Demand Supplied (for Customers Charged on this Basis) (MVA)

All entry fields are shaded yellow indicating mandatory data fields however it is noted in RIN that population is only required where Ergon Network charges customers for Maximum Demand supplied. This was also confirmed following AER review of Ergon Network's initial submission of the previous Benchmarking RIN, in which Ergon Energy had calculated (using a conversion factor) data on an 'MVA measure' basis.

Ergon Network commenced charging customers on a kVA (MVA) basis as of 1 July 2015. Where previous years information was not available in regard to MVA measures of Demand Supplied for contracted and Measured demand and "zeroes" were entered. This is consistent with the clarification received from the AER on 8 April 2014, which stated "zeros should be entered into table 3.4.3.7. The correct response to table 3.4.3.7 is to input the demand for which customers are charged. This should be based on the units of measurement upon which the customers were charged. If Ergon Network only charges customers for demand based on MWs then 0s should be input into table 3.4.3.7."

Sources

Table 3.4.3 - System Demand

Demand Supplied (for Customers Charged on this Basis) (MW & MVA)

Ergon Energy Network has sourced data from the Network Billing system (PEACE).

Methodology

Table 3.4.3 - System Demand

Demand Supplied (for Customers Charged on this Basis) (MW & MVA)

Network Use of System (NUOS) charges classed as Network DUOS Capacity Charge (NDCC) were used to identify the Contracted demand proportions for Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) type connections.

NUOS charges classed as Network DUOS Actual Demand Charge (NDADC) were used to identify the Measured demand proportions for ICC, CAC and EG type connections.

All Standard Asset Customer (SAC) - Large connections are noted to only have either an Actual

Demand charge or a Threshold Demand charge and therefore were reported under the Contracted Demand split. In the case of the Threshold Demand we have used the actual read maximum demand as we have deemed that the demand below the applicable threshold is charged at a zero amount and as such should still be counted as charged.

ICC, CAC and EG type connections are charged (and hence accounted for) on a monthly basis. For 2017-18 onwards the maximum monthly usage per customer is summated to provide the relevant figure, whereas previously, summated values were the summation of the monthly chargeable quantities.

Assumptions

No assumptions were made.

Estimated Information

Not applicable. Ergon Energy has provided actual information.

Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

BOP - 3.5 Physical Assets

Table 3.5.1 - Network Capacities 1

Compliance with the RIN Requirements

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

Circuit lengths has been calculated from the line length (measured in kilometres) of lines that are in service and regulated (total length of feeders including all spurs), where each single wire earth return (SWER) line, single phase line, and three phase line count as one line. A double circuit line has been counted as two lines. Circuit lengths do not take into account vertical components such as sag and end lengths.

Sources

The data for 3.5.1.1 and 3.5.1.2 (overhead and underground network length) comes from the Ergon Energy Smallworld replicated spatial database. This database is replicated from the Smallworld geographic information (GIS) electrical data store.

Methodology

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

Scripts were run against the snapshot of Smallworld data taken on the 1st of July to extract the number and length of conductors broken down by voltage and type. Conductors that did not align with any of the prescribed categories were placed in the other groupings. Conductors with voltages of 12.7kV and 19.1kV were placed in the SWER category.

Services lines are not separately identified within the Ergon Energy's systems but are represented as standard LV overhead line. Service lines were identified, calculated and removed from the LV line total lengths. Service lines were found by finding LV with a connection point at one end and a length of less than 50m. Where an LV line is greater than 50m the length of the LV line was reduced by 50m and added to the service line totals.

Assumptions

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

It is assumed that the maximum length of a service line is 50m.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this Template.

Explanatory Notes

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

Not applicable.

Table 3.5.1 - Network Capacities 2

Compliance with the RIN Requirements

Circuit capacity (MVA): Overhead low voltage distribution

Ergon Energy has provided estimated typical or weighted average capacity for overhead low voltage class within our network as prescribed by the AER, under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant.

Capacity has been provided in an MVA measure.

On 4 February 2015, the AER provided (at Ergon Energy's request) the following clarification with regards to requirements in respect of reporting requirements for these tables:

We are not requesting separate weighted average capacities for summer and winter. We are requesting the weighted average capacity for the whole network in summer if the majority of that network experiences maximum demand in summer. Conversely, we are requesting the weighted average capacity for the whole network in winter if the majority of that network experiences maximum demand in winter. ....That is, we are requesting the weighted average MVA capacity circuit capacity calculated using the capacities (under system normal conditions) at the time of overall system Maximum Demand.

Further to this, on 3 December 2013, the AER provided the following clarification to NSPs:

...variables contained within [Tables 6.1.1 and] 6.1.3 do not include the length or capacity of service lines. The correct, compliant completion of Tables 6.1.1 and 6.1.3 is to report the circuit length and circuit capacity excluding the circuit length and circuit capacity of service lines.

A stakeholder has asked whether two sets of lines that run on different sets of poles (or towers) but share the same easement should count as one route or two for the variable DOEF0301. We confirm that in this instance the lines are to be counted separately. The correct, compliant response to the variable DOEF0301 where two sets of lines share the same easement but run on separate sets of poles (or towers) is to count these lines as separate routes when reporting total route line length.

The entry field which is shaded yellow indicating a mandatory data field has been populated.

Sources

Refer to the methodology section

Methodology

Circuit capacity (MVA): Overhead low voltage distribution

Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to variable [DPA0301] Overhead low voltage distribution lines contained in Template 3.5, Table 3.5.1.3.

As per previous submissions unknown overhead low voltage conductors have been assumed to be small copper conductor (0.080").

On this basis Ergon Energy considers that the best estimate has been provided.

Assumptions

Circuit capacity (MVA): Overhead low voltage distribution

Not applicable.

Estimated Information

Circuit capacity (MVA): Overhead low voltage distribution

Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to variable [DPA0301] Overhead low voltage distribution lines contained in Template 3.5, Table 3.5.1.3.

As per previous submissions unknown overhead low voltage conductors have been assumed to be small copper conductor (0.080").

On this basis Ergon Energy considers that the best estimate has been provided.

Explanatory Notes

Circuit capacity (MVA): Overhead low voltage distribution

Not applicable.

Table 3.5.1 - Network Capacities 3

Compliance with the RIN Requirements

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

Ergon Energy has provided estimated typical or weighted average capacities for each of the listed overhead voltage classes (3.5.1.3) and underground voltage classes (3.5.1.4) within our network as prescribed by the AER, under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant.

Capacity has been provided in an MVA measure.

On 4 February 2015, the AER provided (at Ergon Energy's request) the following clarification with regards to requirements in respect of reporting requirements for these tables:

We are not requesting separate weighted average capacities for summer and winter. We are requesting the weighted average capacity for the whole network in summer if the majority of that network experiences maximum demand in summer. Conversely, we are requesting the weighted average capacity for the whole network in winter if the majority of that network experiences maximum demand in winter. ....That is, we are requesting the weighted average MVA capacity circuit capacity calculated using the capacities (under system normal conditions) at the time of overall system Maximum Demand.

Further to this, on 3 December 2013, the AER provided the following clarification to NSPs:

...variables contained within [Tables 6.1.1 and] 6.1.3 do not include the length or capacity of service lines. The correct, compliant completion of Tables 6.1.1 and 6.1.3 is to report the circuit length and circuit capacity excluding the circuit length and circuit capacity of service lines.

A stakeholder has asked whether two sets of lines that run on different sets of poles (or towers) but share the same easement should count as one route or two for the variable DOEF0301. We confirm that in this instance the lines are to be counted separately.The correct, compliant response to the variable DOEF0301 where two sets of lines share the same easement but run on separate sets of poles (or towers) is to count these lines as separate routes when reporting total route line length.

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Consistent with the clarification received from the AER, Ergon Energy has reported against those asset categories previously reported against and have left blank any categories that are not relevant to its business. [DPA0303, DPA0308, DPA0312, DPA0402, DPA0404, DPA0407].

Sources

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

Ergon Energy has sourced data from, and referred to the following standards or guidelines, in order to complete variables for Estimated Overhead Network Weighted Average Capacity, by Voltage Class (MVA):

- SOREP Oracle Spatial database (replicated SmallWorld GIS electrical datastore);
- Australian Standards;
- IEC Standards;
- ESAA D(b)5; and
- Ergon Energy Plant Rating Guidelines.
- Olex cable manufacturer catalogue calculations.

Methodology

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

Data in relation to Table 3.5.1.1 'Overhead network length of circuit at each voltage' was used. A methodology was employed whereby for lines interacting with more than one climate zones, the lowest rating was applied. Summer ratings were calculated.

Voltage drop and thermal limits of circuit components other than overhead lines and cables have not been considered when establishing the capacities of lines.

Data in relation to Table 3.5.1.2 'Underground circuit length each voltage' was used. Of note, the following assumptions were applied.

- Cables with similar characteristics have been given the same rating;
- Cable ambient air temperatures were calculated from spatial analysis with Ergon Energy Climate Zones;
- Cable ground temperatures were calculated from spatial analysis with 9 BOM Weather stations (nearest);
- Unknown Voltage & Phase attributes were calculated from cable characteristics;
- Cable ratings assumed 2 adjacent cables, 900mm depth, Cyclic Rating Factor =1, Solid Bonded & TR=2.0;
- Summer & Winter Ratings were calculated.

Voltage drop and thermal limits of circuit components other than overhead lines and cables have not been considered when establishing the capacities of cables.

Assumptions

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

No assumptions were made.

Estimated Information

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this Template.

Explanatory Notes

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

The information in this template is a non-financial data set (both estimated and actual data), and accordingly is not impacted by any changes in accounting policy

For Table 3.5.1.3, it is noted that the result for "DPA0312 Overhead 132 kV Capacity" has dramatically changed when compared to the previous year. This is due to a re-rating of 132kV feeder 7174 Columboola (304.49km) maximum design rating from 75 down to 50 degrees Celsius. In addition, 163.33km of new OH 132kV segments were added with 133.37km relating to a single renewable connection.

This change has been translated into Smallworld Electronic Office in the last year resulting in dramatic changes in determining the average capacity (MVA) for this asset category.

For Table 3.5.1.4 other voltage (DPA0413): the capacity reported related to four segments of 3.3kV underground conductor (total length 327m) associated with the Sunwater Monduran Dam connection. This connection also had 548m of overhead conductor with the associated capacity being reported in Table 3.5.1.3 other voltage (DPA0313).

Table 3.5.2 - Transformer Capacities 1

Compliance with the RIN Requirements

Distribution transformer capacity owned by High Voltage Customers

Where the transformer capacity owned by the customers connected at high voltage (DPA0502) was not available, Ergon Energy reported the summation of individual Maximum Demands of high voltage customers whenever they occur (i.e. the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers. This is consistent with the Instructions and Definition document issued by the AER in November 2013 which states:

"When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for Distribution Transformer capacity owned by High Voltage Customers it must do so; otherwise Ergon Energy must provide Estimated Information."

Sources

Data is the maximum of : last years data, actual demand this last year, and authorised demand for a connection.

Data from last year is from last years RIN data

Data for actual demand is the maximum demand billed in Ergons billing system PEACE during the year for each connection. Data is from monthly SOC PEACE billing reports.

Authorised demand is recorded from our Tariff files, which are updated from Connection agreements as required.

Connections that have been de-energised during a period are deleted from file.

Methodology

Distribution transformer capacity owned by High Voltage Customers

The following approach was applied to calculating Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- As the transformer capacity owned by customers at high voltage was largely not available, the calculation was based on the recorded annual peak demands; with each customers capacity estimated to be the standard transformer capacity greater than their historical peak demands and
- Where capacities were available these values were used.

Assumptions

Distribution transformer capacity owned by High Voltage Customers

The following assumptions and limitations apply to Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- Transformer capacity for each high voltage customer is estimated from their individual annual peak demands recorded between 2006 and 2020.

Estimated Information

Distribution transformer capacity owned by High Voltage Customers

Estimated Information has been presented for Distribution Transformer Capacity owned by High Voltage Customers (DPA0502) in accordance with the Instruction at Table 3.5.2 Transformer Capacities Variables.

Ergon Energy believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

Distribution transformer capacity owned by High Voltage Customers

Not applicable.

Table 3.5.2 - Transformer Capacities 2

Compliance with the RIN Requirements

Table 3.5.2 - Transformer Capacities Variables

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Distribution Transformer Total Installed Capacity

Distribution transformer capacity owned by Ergon Energy (DPA0501) - the reported data is the nameplate continuous rating including forced cooling.

DPA0503 Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon Energy but not currently in use. Cold Spare Capacity is included in Distribution transformer capacity owned by Ergon Energy (DPA0501).

Cold Spare Capacity (Distribution Transformer and Zone Substation)

Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon Energy but not currently in use. Cold Spare capacity is included in the total Distribution transformer capacity owned by Ergon Energy (DPA0501), and total zone substation transformer capacity (DPA0604).

Zone Substation Transformer Capacity

Measures are the summation of normal assigned continuous capacity/rating (with forced cooling or other capacity improving factors included). They include both energised transformers and cold spare capacity.

The assigned rating must be (if available) the rating determined from results of temperature rise calculations from testing, else the nameplate rating is reported.

For zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders is reported instead of transformer capacity.

Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon Energy but not currently in use. Cold spare capacity is included in the total zone substation transformer capacity (DPA0604). It is noted that year's submission of Cold Spare Capacity includes the addition spare substation transformer capacity (i.e. standby transformers), in accordance with the AER's definition of "Cold Spare Capacity".

Sources

<u>**Distribution Transformer Total Installed Capacity**</u>

DPA0501 - Distribution transformer capacity owned by utility

The source data is retrieved via FME Workbench's examination of Ergon Energy's corporate database for the 2019-20 period.

DPA0502 - Distribution transformer capacity owned by High Voltage Customers

The source data for Distribution transformer capacity owned by High Voltage was obtained from the DCOS and PEACE billing reports

DPA0503 - Cold spare capacity included in DPA0501

The source data is retrieved via inventory records from Stock on Hand distinguishing both Owned Stock and Refurbished Owned Stock. Values provided are based upon stock on hand values that are in Inventory as of the first day of day of July 2019. These items may or may not have been purchased for a specific project, these also include those deemed as a Critical Spare; Strategic Spare or Project Spare for a particular location/substation but have yet to be issued out of Inventory. All items sitting within Inventory that have not been issued a work order are counted.

DPA0503 = SOH(Owned Stock) + SOH(Refurbished Owned Stock)

<u>Zone Substation Transformer Capacity</u>

DPA0601, DPA0602 and DPA0603

2019-20 totals are based on current corporate data extracted from Ellipse as a snapshot of the system at the end of the 2019-20 regulatory year via the FME Workbench.

DPA0604 - Total zone substation transformer capacity

2019-20 totals are based on current corporate data extracted from Ellipse as a snapshot of the system at the end of the 2019-20 regulatory year via the FME Workbench.

DPA0605 - Cold spare capacity of zone substation transformers included in DPA0604

The source data is retrieved via SIFT substation records for the relevant financial year and inventory records from Stock on Hand distinguishing both Owned Stock and Refurbished Owned Stock. Values provided are based upon stock on hand values that are in Inventory as of the first day of day of July 2019. These items may or may not have been purchased for a specific project, these also include those deemed as a Critical Spare; Strategic Spare or Project Spare for a particular location/substation but have yet to be issued out of Inventory. All items sitting within Inventory that have not been issued a work order are counted.

<u>Distribution - other transformer capacity</u>

Distribution other - transformer capacity owned by utility

There are no items or records that identify other transformer capacity items owned by the utility.

Methodology

<u>**Distribution Transformer Total Installed Capacity**</u>

DPA0501 - Distribution transformer capacity owned by utility

The source data is retrieved via FME Workbench's examination of Ergon Energy's corporate database for the 2019-20 period.

DPA0502 - Distribution transformer capacity owned by High Voltage Customers

The total capacity of installed distribution transformers was sourced from a Current State Assessment database which each year stores the amount of distribution transformer capacity connected to each distribution feeder. The installed distribution transformer capacity is stored in Ergon Energy's corporate database.

DPA0503 - Cold spare capacity included in DPA0501

The source data is retrieved via inventory records from Stock on Hand distinguishing both Owned Stock and Refurbished Owned Stock. Values provided are based upon stock on hand values that are in Inventory as of the first day of day of July 2019. These items may or may not have been purchased for a specific project, these also include those deemed as a Critical Spare; Strategic Spare or Project Spare for a particular location/substation but have yet to be issued out of Inventory. All items sitting within Inventory that have not been issued a work order are counted.

DPA0503 = SOH(Owned Stock - distribution transformer) + SOH(Refurbished Owned Stock-distribution transformer)

<u>Zone Substation Transformer Capacity</u>

DPA0601, DPA0602 and DPA0603

2019-20 totals are based on current corporate data extracted from Ellipse as a snapshot of the system at the end of the 2019-20 regulatory year via the FME Workbench.

DPA0604 - Total zone substation transformer capacity

Derived from the following items:

DPA0604 = DPA0601 + DPA0602 + DPA0603 + DPA0605

DPA0605 - Cold spare capacity of zone substation transformers included in DPA0604

The source data is retrieved via SIFT substation records for the relevant financial year and inventory records from Stock on Hand distinguishing both Owned Stock and Refurbished Owned Stock. Values provided are based upon stock on hand values that are in Inventory as of the first day of day of July 2019. These items may or may not have been purchased for a specific project, these also include those deemed as a Critical Spare; Strategic Spare or Project Spare for a particular location/substation but have yet to be issued out of Inventory. All items sitting within Inventory that have not been issued a work order are counted.

DPA0605 = SOH(Owned Stock - zone substation transformer) + SOH(Refurbished Owned Stock-zone substation transformer) + Zone Substation Standby Transformers

Distribution - other transformer capacity

Distribution other - transformer capacity owned by utility

There are no items or records that identify other transformer capacity items owned by the utility.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to the following variables contained in Table 3.5.2:

- Section 3.5.2.1 -Distribution Transformer Total Installed Capacity
    - DPA0501 Distribution transformer capacity owned by utility
    - DPA0503 Cold spare capacity included in DPA0501
- Section 3.5.2.2 - Zone Substation Transformer Capacity
    - DPA0601 Total installed capacity for first step transformation where there are two steps to reach distribution voltage
    - DPA0602 Total installed capacity for second step transformation where there are two steps to reach distribution voltage
    - DPA0603 Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage
- DPA0604 Total zone substation transformer capacity
- DPA0605 Cold spare capacity of zone substations transformers included in DPA0604

Explanatory Notes

The information in this template is a non-financial data set (both estimated and actual data), and accordingly is not impacted by any changes in accounting policy

Table 3.5.3 - Public Lighting

Compliance with the RIN Requirements

The AER requires Ergon Energy to report the number of public lighting luminaires and public lighting poles in its network. For both variables, Ergon Energy is required to report numbers that include both assets owned by Ergon Energy and assets operated and maintained, but not owned by Ergon Energy. Only poles that are used exclusively for public lighting are to be included.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Public Lighting in Table 7-1.

Table 7-1 Consistency with Notice Requirements

Variable	Consistency with Notice requirements	Addressing basis of preparation requirements
DPA0701 to DPA0703	Public Lighting	All entry fields which are shaded yellow indicating mandatory data fields have been populated for the 2019-20 regulatory year.

Sources

Public Lighting data has been sourced from the PLUMS database and Smallworld GIS.

Methodology

For Public Lighting Luminaries a methodology was employed whereby Pivot tables were developed from PLUMS database to identify Public Lighting assets that were established in the database at the end of each regulatory year (financial year). Only Ergon Owned and Operated and Gifted and Ergon Operated lights have been included (previously known as Rate 1 & 2).

For Public Lighting Poles a methodology was employed whereby a query was run through Smallworld to identify Public Lighting assets that did not have Network Wires attached and as such were Street Light Only Poles. Customer Owned and Operated poles were excluded (previously known as Rate 3).

It is assumed that the Smallworld data is an accurate record of actual assets.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this Template.

Explanatory Notes

The information in this template is a non-financial data set (actual data), and accordingly is not impacted by any changes in accounting policy

BOP - 3.6 Quality of Service

Table 3.6.1 - Reliability

Compliance with the RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.1 Reliability, 3.6.2 System Losses and 3.6.3 Capacity Utilisation Network Feeders reported in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Sources

Ergon Energy has sourced data from its internal outage management and asset management systems.

Methodology

Table 3.6.1 Reliability

For the regulatory (financial) year 2019-20, Major Event Day Threshold (tMed 7.78) was calculated utilising 5 years of Daily SAIDI data using the required STPIS methodology.

Table 3.6.1 DQS0101 to DQS0108: As relevant, Ergon Energy has applied definitions and methodology as set out in the AER's Electricity DNSPs, STPIS (November 2009), which remains applicable for the current regulatory control period. The following comments are made across all variables.

- Ergon Energy notes that Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period (1 July) and the number of customers at the end of the reporting period (30 June), rounded up to nearest whole number) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.
- Only completed unplanned sustained (> 1min) interruptions are included.
- In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of Urban, Short Rural & Long Rural (Customer Minutes, Customer Interruptions and Customer Numbers).
- An event caused by a customer's electrical installation or failure of that electrical installation which only affects supply to that customer is not deemed an interruption as defined, "A

sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network" STPIS 2009 and CA RIN Appendix E 18.2]. These events have been confirmed through site inspection to have resulted from faults and failures within the customer's installation and as such are considered to be an event beyond the boundary of the electricity supply network and therefore excluded from Ergon Energy reported reliability performance under the STPIS.

Inclusive of MEDs

The following comments are made in relation to specific Reliability variables, provided in Template 3.6 Table 3.6.1 (Reliability performance **inclusive** of MEDs).

DQS0101 - Whole of network unplanned SAIDI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0102 - Whole of network unplanned SAIDI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Inclusive of the exclusions in clause 3.3(b) and exclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

DQS0103 - Whole of network unplanned SAIFI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers interrupted divided by average number of customers

- Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0104 - Whole of network unplanned SAIFI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Inclusive of the exclusions in clause 3.3(b) and exclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

Exclusive of MEDs

The following comments are made in relation to specific Reliability variables, provided in Template 3.6 Table 3.6.1 (Reliability performance **exclusive** of MEDs).

DQS0105 - Whole of network unplanned SAIDI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Exclusive of the exclusions in clause 3.3(b) and Inclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0106 - Whole of network unplanned SAIDI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customers minutes divided by average number of customers

- Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network

DQS0107 - Whole of network unplanned SAIFI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Exclusive of the exclusions in clause 3.3(b) and Inclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0108 - Whole of network unplanned SAIFI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all Reliability statistics.

Data represents Actual performance only in relation to unplanned interruptions, as defined in the AER's STPIS scheme for Electricity DNSPs (November 2009).

Explanatory Notes

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.6.2 - Energy Not Supplied

Compliance with the RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.2 Energy Not Supplied in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Chapter 7 Table 7.2 approach 3 *"average consumption of customers on the feeder based on their billing history"* as defined in the Economic Benchmarking RIN instructions and definitions (November 2013) has been applied to estimate the energy not supplied.

Sources

Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year.

Consumption for the "Energy Not Supplied" was sourced from the Network billing system Peace.

Methodology

Refer to Table 3.6.2: As relevant, Ergon Energy has applied definitions and methodology as set out in the AER's Electricity DNSPs, STPIS (November 2009) and Economic Benchmarking RIN instructions and definitions (November 2013), which remains applicable for the current regulatory control period. The following comments are made across all variables.

- The Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period (1 July) and the number of customers at the end of the reporting period(30 June)) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.
- Only completed unplanned sustained (> 1min) interruptions are included.
- In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of Urban, Short Rural & Long Rural (Customer Minutes, Customer Interruptions and Customer Numbers).

An event caused by a customer's electrical installation or failure of that electrical installation which only affects supply to that customer is not deemed an interruption as defined, "A sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network" STPIS 2009 and CA RIN Appendix E 18.2]. These events have been confirmed through site inspection to have resulted from faults and failures within the customer's installation and as such are considered to be an event beyond the boundary of the electricity supply network and therefore excluded from Ergon Energy reported reliability performance under the STPIS

All export and import meter data from Peace for the regulatory reporting year for each NMI was extracted and loaded into a table. The standing data from PEACE for each NMI linking to the relevant Feeder was placed in this table. A query was then run to consolidate all NMIs' consumption data relating to each feeder to give their annual consumption. This total is then used to calculate the average customer consumption per minute per feeder.

Ergon Energy has estimated the Energy Not Supplied using data reported for unplanned/planned customer minutes off supply (Mins) multiplied by the average consumption by feeder (in minutes) sourced from Peace. This is in accordance with methodology Chapter 7, Table 7.2 approach three *"average consumption of customers on the feeder based on their billing history"* as defined in the Economic Benchmarking RIN instructions and definitions (November 2013) for energy not supplied, inclusive of the exclusions under clause 3.3(b) (Major Event Days) and exclusive of the exclusions in accordance with clauses 3.3(a) of the AER's STPIS scheme and exclusive of Customer Installation Faults/Failures which reside beyond the electricity supply network.

The calculations are based on current connectivity by feeder and not connectivity at the time of the outage. For some feeders that no longer active or have changed connectivity in the system ECORP the average consumption per minute over all feeders is used. The methodology adopted is irrespective of the time of day the outages occurred.

This calculation was performed for both Planned and Unplanned interruptions, with Total Energy Not supplied being the sum of DQS0201 and DQS0202.

Assumptions

Refer to 7.12 Estimated Information.

Estimated Information

By definition, Ergon Energy has provided 'Estimated Information' in relation to all variables contained in Template 3.6 Table 3.6.2.

Historical feeder connectivity is not captured by Ergon Energy, and therefore current connectivity is assumed. Consumption is identified for all feeders and was multiplied by the customer minutes. Where there is no current connectivity an average consumption across all feeders was used.

This is consistent with the Instructions and Definition document issued by the AER in November 2013, which states

"When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for energy not supplied it must do so; otherwise Ergon Energy must provide Estimated Information."

Ergon Energy believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

Energy Not Supplied is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.6.3 - System Losses

Compliance with the RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.1 Reliability, 3.6.2 System Losses and 3.6.3 Capacity Utilisation Network Feeders reported in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

System losses are calculated in accordance with Equation 2 in the Instructions and Definitions at Appendix B to the RIN.

Sources

Ergon Energy has sourced data from its corporate sources, as detailed in the BOPs for Template 3.4 Operational data - see Energy Received and Energy Delivery for more details.

Methodology

All data provided in relation to System Losses is Actual information which is calculated using the following formula:

[Energy Received - Energy Delivery] *divide* Energy Received.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all Reliability statistics.

Data represents Actual performance only in relation to unplanned interruptions, as defined in the AER's STPIS scheme for Electricity DNSPs (November 2009).

Explanatory Notes

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.6.4 - Capacity Utilisation

Compliance with the RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.1 Reliability, 3.6.2 System Losses and 3.6.3 Capacity Utilisation Network Feeders reported in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Capacity Utilisation

For this measure, capacities used are the summation of normal assigned continuous capacity/rating (with forced cooling or other capacity improving factors included).

The assigned rating must be (if available) the rating determined from results of temperature rise calculations from testing, else the nameplate rating is reported.

For zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders is used instead of transformer capacity.

Sources

DQS04 - Overall Utilisation

Ergon Energy has sourced data to report capacity utilisation from the same sources as those reported for 'DOPSD0201 non-coincident summated raw system annual maximum demand at the zone substation level' (i.e. EB RIN Template 3.4) and 'DPA0604 Total zone substation transformer capacity' (i.e. EB RIN Template 3.5).

Methodology

DQS04 - Overall Utilisation

This data (DQS04) was determined by dividing the 'Non-coincident Summated Raw System Annual Maximum Demand' provided as per DOPSD0201 by the 'Total zone substation transformer capacity' as per DPA0604 whilst disregarding the 'Cold Spare Capacity' component (DPA0605). Hence, DQS04 can be calculated in either two ways, namely:

DQS04 = DOPSD0201 / (DPA0601 + DPA0602 + DPA0603)

or alternatively,

DQS04 = DOPSD0201 / (DPA0604 - DPA0605)

{where DPA0604 = DPA0601 + DPA0602 + DPA0603 + DPA0605}

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all Reliability statistics.

Data represents Actual performance only in relation to unplanned interruptions, as defined in the AER's STPIS scheme for Electricity DNSPs (November 2009).

Explanatory Notes

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

BOP - 3.7 Operating Environment

Table 3.7.1 - Density Factors

Compliance with the RIN Requirements

All mandatory data entry fields have been populated.

Sources

The source data for each numerator/denominator input is noted below in the section on methodology.

Methodology

Values were obtained by using the following calculation as required in Instructions and Definitions for variables:

- "DOEF0101 - Customer density" was calculated by dividing the total number of customers (DOPCN01 from RIN Table 3.4.2.1) divided by the route Line Length (DOEF0301 from RIN Table 3.7). No conversions are required.
- "DOPED0102 - Energy density" was calculated by dividing the total energy delivered to customers (DOPED01) by the total number of customers (DOPCN01) from RIN Table 3.4.2. The energy delivered was multiplied by 1000 to convert the figures to MWh.
- "DOPED0103 - Demand density" was calculated by dividing the total non-coincident system annual maximum demand (DOPSD0201 from RIN Table 3.4.3.3) by the total number of customers (DOPCN01 from RIN Table 3.4.2.1) from RIN Table 3.4.2. The total non-coincident system annual maximum demand was multiplied by 1000 to convert the figures to kVA.

Further information on the methodology employed to determine each numerator or denominator input is available in Table 4: Routine Line Length, as well as in the relevant sections of the BOP for EB RIN Template 3.4 Operational data for DOPCN01, DOPED01, DOPSD0201.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined terms)

Explanatory Notes

Not applicable.

Table 3.7.2 - Terrain Factors

Compliance with the RIN Requirements

DOEF0201 (rural proportion) and DOEF0205 (total spans) are shaded yellow indicating they are mandatory data fields, and accordingly have been populated.

Vegetation maintenance span cycles variables (DOEF0206-DOEF0207) have been provided as Actual Information.

Sources

The source data for each variable is contained below in the section on methodology

Methodology

Table 3.7.2-1 Terrain Factors (RIN Table 3.7.2)

	Addressing Basis of Preparation Requirements
Rural proportion (DOEF0201)	Data in relation route lengths of lines / cables has been sourced from Smallworld. Data in relation to feeder categories has been sourced from FeederSTAT (Ergon's outage management system). Ergon's unregulated, isolated systems and sub-transmission feeders (according to the definition) have been removed from this calculation. Low voltage line/cable don't have a feeder attribute, therefore do not have a feeder category classification. It is assumed that will be classified as 'Non Rural'. Spans on multiple circuits are only calculated once. Information provided is Actual
Urban and CBD and Rural vegetation maintenance spans (DOEF0202DOEF0203) **Total vegetation maintenance spans** **(DOEF0204)**	This information is collated from the vegetation contractors database systems in which all this information is recorded
Total number of spans (DOEF0205	Total number of spans has been sourced from Smallworld. Information is Actual Information. DOEF0205 does not include service line spans. Spans on multiple circuits are only counted once.

Average urban and CBD vegetation maintenance span cycle (DOEF0206) **Average rural vegetation maintenance span cycle (DOEF0207)**	2019-20 average maintenance span cycle was calculated based on data sourced from the June monthly report for the Annual Vegetation Management Program (June 2019) taken from the Ellipse database (i.e. 2019-20 data was found in the June 2019 report). A methodology was employed whereby: • Average urban vegetation maintenance span cycle = (Sum of treated Urban vegetation zones cycle duration [Maintenance Schedule Task]/total number of Urban Vegetation Zones treated during regulatory (financial)year; • Average rural vegetation maintenance span cycle = (Sum or treated Rural vegetation zones cycle duration [Maintenance Schedule Task]/total number of Rural Vegetation Zones treated during regulatory (financial) year. The information provided is considered actual.
Average number of trees per urban and **CBD vegetation maintenance span (DOEF0208)** **Average number of trees per rural vegetation maintenance span (DOEF0209)**	This information is collated from the vegetation contractors database systems in which all this information is recorded
Average number of defects per urban and **CBD vegetation maintenance span (DOEF0210)** **Average number of defects per rural vegetation maintenance span (DOEF0211)**	This information is equal to the average number of trees per span as each tree is considered a defect
Tropical proportion (DOEF0212)	The tropical proportion of Ergon Energy's network was based on network data sourced from the Smallworld GIS. The number of maintenance spans (refer to DOEF0205) occurring within hot humid summer and warm humid summer regions as sourced from the Bureau of Meteoroloogy (BOM) Information provided is considered Actual.
Standard Vehicle Access (DOEF0213)	The route line length without standard vehicle access was calculated by identifying the line length that falls outside the extents of the road reserve boundaries. Information provided is considered actual.

Bushfire Risk (DOEF0214)	The bushfire risk proportion of Ergon Energy's network was based on network data sourced from the Smallworld GIS. The number of maintenance spans (refer to DOEF0205) occurring within the high bushfire risk areas as sourced from the Queensland Fire and Rescue Service (QFRS). Information is considered Actual.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined terms)

Explanatory Notes

Not applicable.

Table 3.7.3 - Service Area Factors

Compliance with the RIN Requirements

All mandatory data entry fields, shaded yellow, have been populated.

Route Line length of lines is based on the distance between line segments. It does not include vertical components such as line sag.

The route Line Length does not equate to the circuit length as the circuit length includes multiple circuits. The circuit length is reported excluding the circuit length of service lines.

Following AER clarifications provided in relation to variable DOEF0301 which noted the intent of this variable is to measure the aggregate distance between poles and/or towers, Ergon Energy confirms that where:

- two sets of lines that run on different sets of poles (or towers) share the same easement the lines are counted separately;
- there are multiple circuits on a span, the length of each span is considered only once; and
- a span shares multiple voltages, the length of the span is also considered only once; and captures the length of both underground cables and overhead lines

Sources

Ergon Energy has sourced data from its SOREP Oracle Spatial database. This database is replicated from the Smallworld GIS electrical data store.

Methodology

For 2019-20, an assessment of data from Smallworld was required.

The route length of all conductors and cable excluding service lines.

Spans on multiple circuits are only counted once.

Information provided for 2019-20 is considered actual in accordance with the AER's requirements.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined terms)

Explanatory Notes

Not applicable.